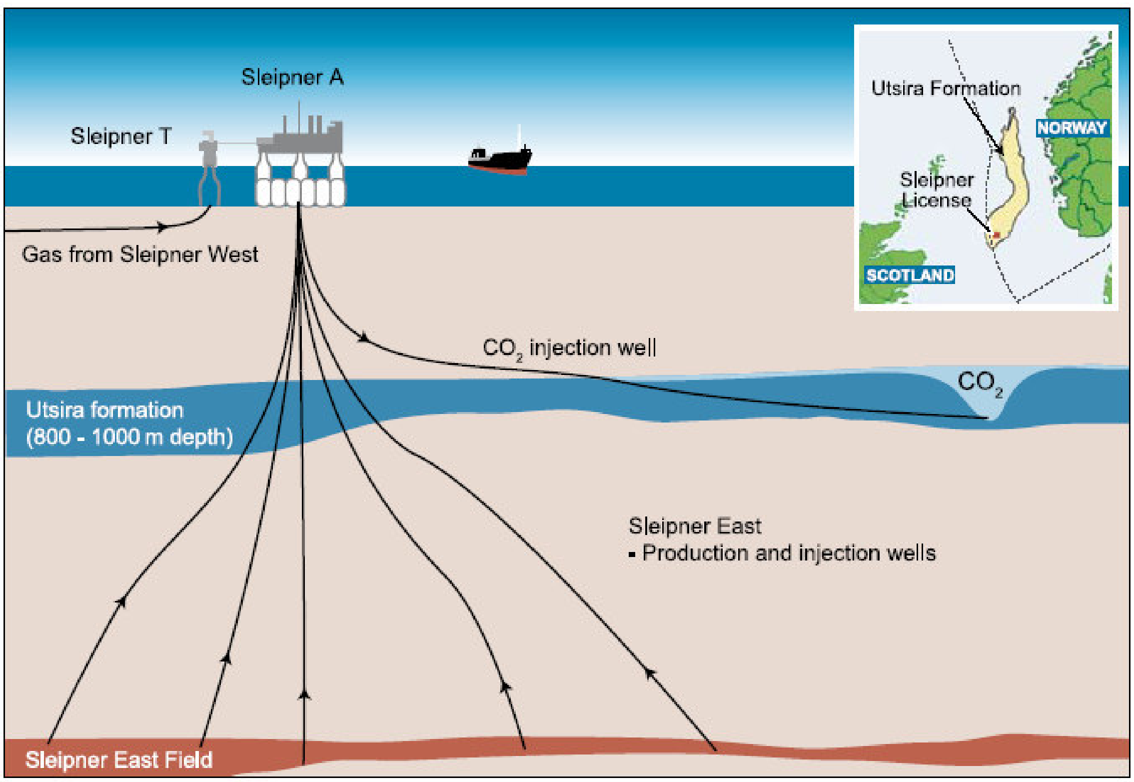
Carbon Dioxide Storage: Geological Security and Environmental Issues – Case Study on the Sleipner Gas field in Norway



(Figure courtesy of Statoil)

Semere Solomon

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Executive Summary

Carbon dioxide capture and storage (CCS) is one option for mitigating atmospheric emissions of carbon dioxide and thereby contributes in actions for stabilization of atmospheric greenhouse gas concentrations. The Bellona Foundation is striving to achieve wide implementation of carbon dioxide (CO_2) capture and storage both in Norway and internationally. Bellona considers CCS as the only viable large scale option to close the gap between energy production and demand in an environmentally sound way, thereby ensuring that climate changes and acidification of the oceans due to increased CO_2 concentrations in the atmosphere will be stabilised.

Carbon dioxide storage in geological formations has been in practice since early 1970s. 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. Injection of CO_2 in deep geological formations uses technologies that have been developed for, and applied by, the oil and gas industry to meet the needs of geological storage. 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.

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, 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 be trapped underground by various storage mechanisms, such as: trapping below an impermeable, confining layer (caprock); retention as an immobile phase trapped in the pore spaces of the storage formation; and/or dissolved in the *in situ* formation fluids. Additionally, it may be trapped by reacting with the minerals in the storage formation and caprock to produce carbonate minerals. CO_2 becomes less mobile over time as a result of multiple trapping mechanisms, further lowering the prospect of leakage, which builds the confidence in geological security of carbon dioxide storage.

Site characterization is a prerequisite to safe geological storage of CO_2. Key goals for geological CO_2 storage site characterization are to assess how much CO_2 can be stored at a potential storage site and to demonstrate that the site is capable of meeting required storage performance criteria. Site characterization requires the collection of the wide variety of geological data that are needed to achieve these goals. Much of the data will necessarily be site-specific. Most data will be integrated into geological models that will be used to simulate and predict the performance of the site. Performance prediction of a site can be made using models that 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.

Monitoring is needed for a wide variety of purposes and monitoring methods can potentially be adapted from existing applications to meet the needs of geological storage. Specifically, to ensure and document the injection process, verify the quantity of injected CO_2 that has been stored by various mechanisms, demonstrate with appropriate monitoring techniques that CO_2 remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO_2 remains stored and that performance predictions can be verified. Finally monitoring is required to detect leakage and provide an early warning of any seepage or leakage that might require mitigating action and to assess environmental effects. Potential risks to humans and ecosystems from geological storage may arise from leaking injection wells, abandoned wells, and 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 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 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.

Geological storage of CO_2 is in practice today beneath the North Sea, where nearly 1 $MtCO_2$ has been successfully injected annually in the Utsira formation at Sleipner since 1996. It is an ideal CO_2 storage site typical of deep saline sedimentary formation. The site is well characterized and the CO_2 injection process was monitored using seismic methods and this provided insights into the geometrical distribution of the injected CO_2 and provided increased understanding of the CO_2 migration within the reservoir. Performance prediction of the site shows that most of the CO_2 accumulates in one bubble under the cap seal of the formation controlled by the topography of the cap seal only. In the long term (> 50 years) the phase behaviour (solubility and density dependence of composition) will become the controlling fluid parameters at Sleipner. The solubility trapping has the effect of eliminating the buoyant forces that drive CO_2 upwards and through time can lead to mineral trapping, which is the most permanent and secure form of geological storage. Recent studies at Sleipner area demonstrate further the geological security of carbon dioxide storage and the monitoring tools (Gravity and Seismic methods) strengthen verification of safe injection of CO_2 in the Utsira formation. Subsequent work in the following years is necessary to reinforce these findings further that CO_2 storage is safe through monitoring and verification procedures that will be able to detect potential leaks.

Conclusions

The security of carbon dioxide storage in geological formations first and foremost depends on careful storage site selection followed by characterization of the selected site in terms of geology, hydrogeology, geochemistry and geomechanics (structural geology and deformation in response to stress changes). The Utsira Formation is well characterized with respect to porosity and permeability (good storage capacity and injectivity), mineralogy, bedding, depth, pressure and temperature. It is a very large aquifer with a thick and extensive clay stone top seal. Available geological information shows absence of major tectonic events after the deposition of the Utsira formation. This means that the geological environment is tectonically stable which implies that the site is suitable for carbon dioxide storage. Microseismic studies suggest the injection of CO_2 in sands of the Utsira Formation has not trigged any measurable microseismicity. This further builds the confidence in geological security of carbon dioxide storage at Sleipner. Moreover, evidence from ten years experience of carbon dioxide storage shows no leakages.

The Sleipner project is a commercial CO_2 injection project and proved that CO_2 capture and storage is a technically feasible and effective method for greenhouse mitigation. It further demonstrates that CO_2 storage is both safe and has a low environmental impact. Monitoring is needed for a wide variety of purposes. Specifically, to ensure and document the injection process, verify the quantity of injected CO_2 that has been stored by various mechanisms, demonstrate with appropriate monitoring techniques that CO_2 remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO_2 remains stored and that performance predictions can be verified. Finally monitoring is required to detect leakage and provide an early warning of any seepage or leakage that might require mitigating action and to assess environmental effects. The work that has been undertaken at Sleipner Gas Field has shown that the injected CO_2 can be monitored within a geological storage reservoir, using seismic surveying. The geochemical and reservoir simulation work have laid the foundations to show how the CO_2 has reacted and what its long term fate in the reservoir will be. The results of the simulations indicate that most of the CO_2 accumulates in a stack of accumulations under thin clay layers interbedded in the sand unit few years after the injection is turned off. The CO_2 plume spreads laterally on top of the brine column and the migration is controlled by the interbedded thin clay layers within the sand unit. In the long term (> 50 years) the phase behaviour (solubility and density dependence of composition) will become the controlling fluid parameters at Sleipner. The solubility trapping has the effect of eliminating the buoyant forces that drive CO_2 upwards and through time can lead to mineral trapping, which is the most permanent and secure form of geological storage.

The recent studies at Sleipner area reveal the integrity of the cap rock (efficient sealing capacity). The injected CO_2 will potentially be trapped geochemically and the regional groundwater flow having an effect on the distribution of CO_2 with the potential of pressure build up as a result of CO_2 injection is unlikely to occur. Monitoring techniques (both Time-lapse Gravity and Seismic methods) proved to be key tools in understanding the whole-reservoir performance. Overall, the recent studies at Sleipner area demonstrate further the geological security of carbon dioxide storage and the monitoring tools strengthen verification of safe injection of CO_2 in the Utsira formation. Subsequent work in the following years is necessary to reinforce these findings further that CO_2 storage is safe through monitoring and verification procedures that will be able to detect potential leaks.

Recommendations

Several CO_2 storage projects are now in operation and being carefully monitored. No leakage of stored CO_2 out of the storage formations has been observed in any of the current projects. Although time is too short to enable direct empirical conclusions about the long-term performance of geological storage, it is an indication that CO_2 can be safely injected and stored at well characterized and properly managed sites. Monitoring of existing projects in the coming 10-20 years is crucial to the broader understanding of CO_2 transport, trapping mechanisms and storage security and to predict long-duration performance. However, if leaks occur, tools for monitoring possible local and regional environmental hazards should be in place together with remediation measures. In this section general recommendations which are thought to contribute to better understanding of geological storage of CO_2 with regard to security and environmental safety. Also the measures needed to be taken in future are listed below.

1) Storage capacity determination for large scale carbon dioxide storage should be determined as accurately as possible. The problem of heterogeneity and porosity should be assessed carefully. Reaction of the CO_2 with formation water and rocks may result in reaction products that affect the porosity of the rock and the flow of solution through the pores. This possibility has not been observed experimentally and its possible effects are not quantified. It is important to assess these effects to get better knowledge about the reservoir and migration patterns of the injected CO_2.
2) During site characterization greatest emphasis are placed on the reservoir and its sealing horizons. However, the strata above the storage formation and caprock also need to be assessed because if CO_2 leaked it would migrate through them.
3) Geological storage projects will be selected and operated to avoid leakage. However, in rare cases, leakage may occur and remediation measures will be needed, either to stop the leak or to prevent human or ecosystem impact. Moreover, the availability of remediation options may provide an additional level of assurance to the public that geological storage can be safe and effective. Therefore appropriate remediation options must be identified in an event of a leakage scenario.
4) The Utsira Formation is a very large aquifer with a thick and extensive claystone top seal. The aquifer is, however, unconfined along its margins. It is important to assess the time required for the migrating CO_2 to reach at the margins of the aquifer.
5) To predict the migration of CO_2 over a period of several thousand years a coarse grid model was used due to computational constraints. However, grid patterns may miss narrow linear anomalies or patterns of linear features on the surface that may reflect deeper fault and fracture systems, which could become natural migration pathways. Future modelling should account such uncertainties.
6) During the SACS project (Best Practice Manual, 2004), the lack of observation boreholes and related samples made it impossible to monitor directly the geochemical processes occurring within the Utsira at Sleipner. Also the interactions of CO_2 with borehole cement were not addressed in the study. Assessment of both issues should be a priority in future monitoring activities.
7) Evaluations on the risk of leakage through injection well, seal, and stress release events due to injection of CO_2 and their probabilities on the release of CO_2 should be a priority. Moreover, quantification of the short-term and long-term Health-Safety-Environmental (HSE) risks, in this case the likelihood of impacts on human and marine life should be assessed.
8) Finally further research on the processes involved in both sealing and in migration of CO_2 in the underground and improved modelling tools is needed to predict future behaviour of a storage location. Modelling tools need to be improved through calibration on real life experiments. Demonstration under different geological conditions is also pointed as important both for improving the understanding but also to prove to the public that storage are safe.

1 Introduction

1.1 Background

Carbon dioxide capture and storage (CCS) is one option for mitigating atmospheric emissions of carbon dioxide thereby contributes in actions for stabilization of atmospheric greenhouse gas concentrations. The Bellona Foundation is striving to achieve wide implementation of CO_2 capture and storage both in Norway and internationally. Bellona considers CO_2 capture and storage as the only viable large scale option to close the gap between energy production and demand in an environmentally sound way, thereby ensuring that climate changes and acidification of the oceans due to increased CO_2 concentrations in the atmosphere will be stabilised. CCS has the potential to reduce overall mitigation costs and increase flexibility in achieving greenhouse gas emission reductions. The widespread application of CCS would depend on technical maturity, costs, overall potential, diffusion and transfer of the technology to developing countries and their capacity to apply the technology, regulatory aspects, environmental issues and public perception.

The greenhouse gas (GHG) making the largest contribution to atmospheric emissions from human activities is carbon dioxide (CO_2). It is released by burning fossil fuels and biomass as a fuel; from the burning, for example, of forests during land clearance; and by certain industrial and resource extraction processes. Emissions of CO_2 due to fossil fuel burning are the dominant influence on the trends in atmospheric CO_2 concentration because according to the International Energy Agency (IEA) 80 % of the global energy consumption is based on coal, oil, and natural gas (IEA, 2005). Global average temperatures and sea level are projected to rise if appropriate measures are not taken. Due to increased emissions of GHG, the global average temperature will increase by 1.4 to 5.8 ^{o}C from 1990 to 2100, according to The Intergovernmental Panel on Climate Change (IPCC, 2001c). The increase in global temperature will have dramatic impacts on life on earth. If no action is taken, the sea level will increase with up to one meter within 2100. One consequence of a one meter rise in sea level is that 40 % of Bangladesh will be under water. Other effects of global warming include increasing precipitation, increased frequency of extreme climate events, disrupting ecosystems, and extinction of species (Wiliams, 2002). Steps should be taken that aim in the stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.

Several technological options for reducing net CO_2 emissions to the atmosphere exist (IPCC, 2005). These include energy efficiency improvements, the switch to less carbon-intensive fuels, nuclear power, renewable energy sources, enhancement of biological sinks, reduction of non-carbon dioxide greenhouse gas emissions and capture and store CO_2 chemically or physically. A variety of factors will need to be taken into account in any comparisons of these mitigation options. The factors include the potential of each option to deliver emission reductions, the national resources available, the accessibility of each technology for the country concerned, national commitments to reduce emissions, the availability of finance, public acceptance, likely infrastructural changes, environmental side-effects, etc. (IPCC, 2005). The IPCC (2001a) found that improvements in energy efficiency have the potential to reduce global CO_2 emissions by 30% using existing technologies. However, on their own, efficiency gains are unlikely to be sufficient, or economically feasible, to achieve deep reductions in emissions of GHGs (IPCC, 2001a). Wider use of renewable energy sources was also found to have substantial potential. Nonetheless, many of the renewable sources face constraints related to cost, intermittency of supply, land use and other environmental impacts (IPCC, 2005). Carbon dioxide capture and storage can be a good option because it can be implemented on a larger scale and has also the potential capacity for deep emission reduction. The Bellona Foundation believes that actions have to be taken now in order to avoid dramatic future climate changes. There is a need for short-term strategies for ensuring energy production with the lowest GHG emissions possible, and the best strategy is to establish carbon capture sequestration (Stangeland *et al*., 2006). Energy production from fossil fuel power plants combined with CO_2 handling including CO_2 capture, transport and safe storage will minimize GHG emissions.

There are three main components of the CCS process: capturing CO_2, for example by separating it from the flue gas stream of a fuel combustion system and compressing it to a high pressure; transporting it to the storage site; and storing it. CO_2 storage will need to be done in quantities of gig tonnes of CO_2 per year to make a significant contribution to the mitigation of climate change. Globally there is a potential of 240 billion ton CO_2 to be captured and stored by 2050 (Stangeland, 2006). This corresponds to a 37 % reduction in global CO_2 emissions in 2050 compared to emissions today. Several types of storage reservoir may provide storage capacities of this magnitude. In some cases, the injection of CO_2 into oil and gas fields could lead to the enhanced production of hydrocarbons, which would help to offset the cost due to the increased income from the increased product. CO_2 capture technology could be applied to fossil-fuelled power plants and other large industrial sources of emissions; it could also be applied in the manufacture of hydrogen as an energy carrier. Most stages of the CCS process build on known technology developed for other purposes.

There are many factors that must be considered when deciding what role CO_2 capture and storage could play in mitigating climate change. These include the cost and capacity of emission reduction relative to, or in combination with other options such as energy efficiency improvements, the switch to less carbon-intensive fuels, nuclear power, renewable energy sources, enhancement of biological sinks or reduction of non-carbon dioxide greenhouse gas emissions; the resulting increase in demand for primary energy sources; the range of applicability; and the technical risk. Other important factors are the social and environmental consequences, the safety of the technology, the security of storage and ease of monitoring and verification, and the extent of opportunities to transfer the technology to developing countries. Many of these features are interlinked. Some aspects are more amenable to rigorous evaluation than others. For example, the literature about the societal aspects of this new mitigation option is limited. Public attitudes, which are influenced by many factors, including how judgements are made about the technology, will also exert an important influence on its application. Of all these aspects, the security of the storage, assessment of monitoring and verification techniques, and environmental considerations are the main topics discussed in this report. The report analyzes the current state of knowledge about the scientific and technical dimensions of CCS option with emphasis on geological storage, security and environmental impacts. This report reviews literature published on geological storage of carbon dioxide in deep saline aquifers with emphasis on the Sleipner Gas field project in Norway.

1.2 Properties of CO2 and Health Effects

Carbon dioxide is a chemical compound of two elements, carbon and oxygen, in the ratio of one to two; its molecular formula is CO_2. It is present in the atmosphere in small quantities (370 ppmv) and plays a vital role in the Earth's environment as a necessary ingredient in the life cycle of plants and animals. During photosynthesis plants assimilate CO_2 and release oxygen. Anthropogenic activities which cause the emission of CO_2 include the combustion of fossil fuels and other carbon containing materials, the fermentation of organic compounds such as sugar and the breathing of humans. Natural sources of CO_2; including volcanic activity, dominate the Earth's carbon cycle. CO_2 gas has a slightly irritating odour, is colourless and is denser than air. At normal temperature and pressure, carbon dioxide is a gas. The physical state of CO_2 varies with temperature and pressure as shown in Figure 1a – at low temperatures CO_2 is a solid; on warming, if the pressure is below 5.1 bar, the solid will sublime directly into the vapour state. At intermediate temperatures (between −56.5^{o}C, the temperature of the triple point, and 31.1^{o}C, the critical point), CO_2 may be turned from a vapour into a liquid by compressing it to the corresponding liquefaction pressure (and removing the heat produced). At temperatures higher than 31.1^{o}C (if the pressure is greater than 73.9 bar, the pressure at the critical point), CO_2 is said to be in a supercritical state where it behaves as a gas; indeed under high pressure, the density of the gas can be very large, approaching or even exceeding the density of liquid water (also see Figure 1b). This is an important aspect of CO_2's behaviour and is particularly relevant for its storage. In an aqueous solution CO_2 forms carbonic acid, which is too unstable to be easily isolated. The solubility of CO_2 in water decreases with increasing temperature and increases with increasing pressure. The solubility of CO_2 in water also decreases with increasing water salinity.

As a normal constituent of the atmosphere, where it is present in low concentrations (currently 370 ppmv or 0.037%), CO_2 is considered harmless. CO_2 is non-flammable. As it is 1.5 times denser than air at normal temperature and pressure, there will be a tendency for any CO_2 leaking from pipe work or storage to collect in hollows and other low-lying confined spaces which could create hazardous situations. The hazardous nature of the release of CO_2 is enhanced because the gas is colourless, tasteless and is generally considered odourless unless present in high concentrations. When contained under pressure, escape of CO_2 can present serious hazards, for example asphyxiation, noise level (during pressure relief), frostbite, hydrates/ice plugs and high pressures (Jarrell *et al*., 2002). The handling and processing of CO2 must be taken into account during the preparation of a health, safety and environment plan for any facility handling CO2.

Most people with normal cardiovascular, pulmonary-respiratory and neurological functions can tolerate exposure of up to 0.5−1.5% CO_2 for one to several hours without harm. Higher concentrations or exposures of longer duration are hazardous – either by reducing the concentration of oxygen in the air to below the 16% level required to sustain human life, or by entering the body, especially the bloodstream, and/or altering the amount of air taken in during breathing; such physiological effects can occur faster than the effects resulting from the displacement of oxygen, depending on the concentration of CO_2. Longer exposure, even to less than 1% concentration, may significantly affect health. Noticeable effects occur above this level, particularly changes in respiration and blood *p*H level that can lead to increased heart rate, discomfort, nausea and unconsciousness.

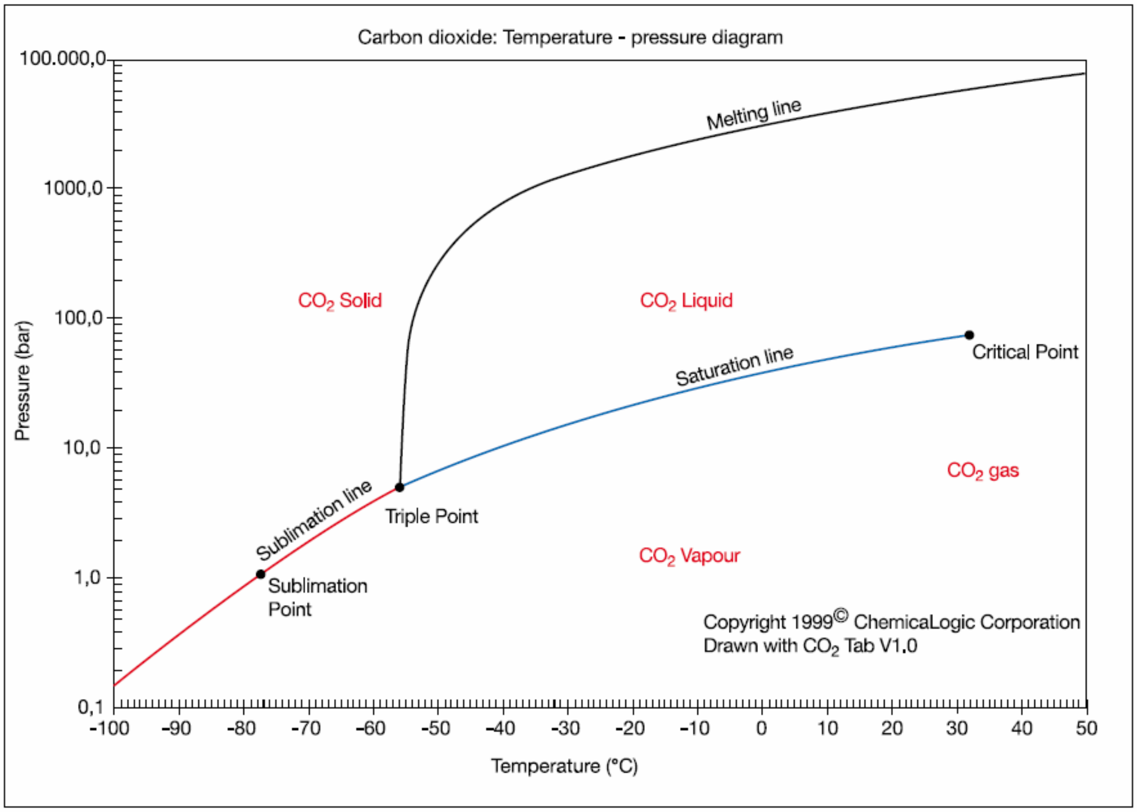

Figure 1a: Phase diagram for CO_2.

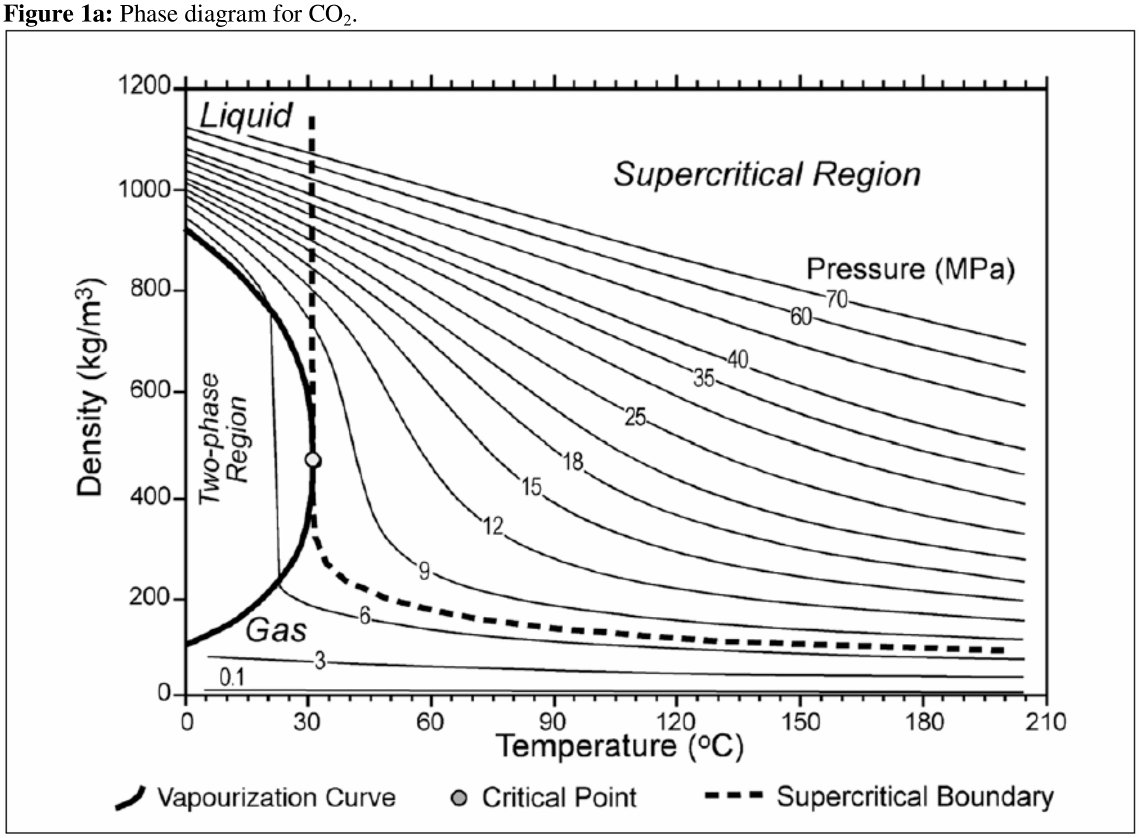

Figure 1b: Variation of CO_2 density as a function of temperature and pressure (Bachu, 2003).

Acute exposure to CO_2 concentrations at or above 3% may significantly affect the health of the general population. Hearing loss and visual disturbances occur above 3% CO_2. Signs of asphyxia will be noted when atmospheric oxygen concentration falls below 16%. Unconsciousness, leading to death, will occur when the atmospheric oxygen concentration is reduced to ≤ 8% although, if strenuous exertion is being undertaken, this can occur at higher oxygen concentrations (Rice, 2004). CO_2 acts as an asphyxiant in the range 7−10% and can be fatal at this concentration; at concentrations above 20%, death can occur in 20 to 30 minutes (Fleming *et al.*, 1992). Health risks to the population could therefore occur if a release of CO_2 were to produce:

- relatively low ambient concentrations of CO_2 for prolonged periods;
- or intermediate concentrations of CO_2 in relatively anoxic environments;
- or high concentrations of CO_2.

1.3 Sources of CO_2

The main source of anthropogenic carbon dioxide (CO_2) emission is the combustion of fossil fuels. Other sources are combustion of biomass-based fuels in certain industrial processes, such as the production of hydrogen, ammonia, iron and steel, or cement. Studies show that the power and industry sectors combined dominate current global CO_2 emissions, accounting for about 60% of total CO_2 emissions (IEA, 2003). The CO_2 emissions in these sectors are generated by boilers and furnaces burning fossil fuels and are typically emitted from large exhaust stacks. Typical examples are large industrial complexes like power plants and refineries with multiple exhaust stacks. These stacks can be described as large stationary sources, to distinguish them from mobile sources such as those in the transport sector and from smaller stationary sources such as small heating boilers used in the residential sector.

1.4 CO_2 Capture and Storage

Carbon dioxide (CO_2) capture and storage (CCS) is a process consisting of the separation of CO_2 from large industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. Capturing CO_2 involves separating the CO_2 from some other gases such as for example, in the flue gas stream of a power plant, the other gases are mainly nitrogen and water vapour. The CO_2 must then be transported to a storage site where it will be stored away from the atmosphere for a very long time (IPCC, 2001a). In order to have a significant effect on atmospheric concentrations of CO_2, storage reservoirs would have to be large relative to annual emissions. Available storage sites have large capacity compared to emitted volumes. The large stationary sources represent potential opportunities for the addition of CO_2 capture plants. The volumes produced from these sources are usually large and the plants can be equipped with a capture plant to produce a source of high-purity CO_2 for subsequent storage. Of course, not all power generation and industrial sites produce their emissions from a single point source. At large industrial complexes like refineries there will be multiple exhaust stacks, which present an additional technical challenge in terms of integrating an exhaust-gas gathering system in an already congested complex, undoubtedly adding to capture costs (Simmonds *et al.*, 2003).

1.5 Context for CO_2 capture and Storage

CO_2 emissions continued an upward trend in the early years of the 21st century. Fossil fuels are the dominant form of energy utilized in the world (86%), and account for about 75% of current anthropogenic CO_2 emissions (IPCC, 2001c). In 2002, 149 Exajoules (EJ) of oil, 91 EJ of natural gas, and 101 EJ of coal were consumed globally (IEA, 2004). Global primary energy consumption grew at an average rate of 1.4% annually between 1990 and 1995; and 1.6% per year between 1995 and 2001. The growth rates by sector are given in Table-1.

Average global CO_2 emissions increased by 1.0% per year between 1990 and 1995 and 1.4% between 1995 and 2001 a rate slightly below that of energy consumption in both periods. In individual sectors, there was no increase in emissions from industry between 1990 and 1995; there was an increase of emissions in other sectors except in the agricultural/other sector where a fall of emission was noted (Table-1).

Total emissions from fossil fuel consumption and flaring of natural gas were 24 $GtCO_2$ per year (6.6 GtC per year) in 2001 – industrialized countries were responsible for 47% of energy-related CO_2 emissions (not including international bunkers). The Economies in Transition[1] accounted for 13% of 2001 emissions; emissions from those countries have been declining at an annual rate of 3.3% per year since 1990. Developing countries in the Asia-Pacific region emitted 25% of the global total of CO_2; the rest of the developing countries accounted for 13% of the total (IEA, 2003).

Table-1: Global energy consumption growth rates and average global CO_2 emissions by sectors (IEA, 2003).

Sector	Global energy consumption growth rate %		Average Global CO_2 emissions %	
	1990-1995	1995-2001	1990-1995	1995-2001
Industrial sector	0.3	0.9	0.0	0.9
Transportation sector	2.1	2.2	1.7	2.0
Building sector	2.7	2.1	2.3	2.0
Agricultural and other sectors	-2.4	-0.8	-2.8	-1.0

1.6 Potential for reducing CO_2 Emissions

It has been determined (IPCC, 2001a) that the worldwide potential for GHG emission reduction by the use of technological options amounts to between 6,950 and 9,500 $MtCO_2$ per year (1,900 to 2,600 MtC per year) by 2010, equivalent to about 25 to 40% of global emissions respectively. The potential rises to 13,200 to 18,500 $MtCO_2$ per year (3,600 to 5,050 MtC per year) by 2020. The evidence on which these estimates are based is extensive but has several limitations: for instance, the data used comes from the 1990s and additional new technologies have since emerged. In addition, no comprehensive worldwide study of technological and economic potential has yet been performed; regional and national studies have generally had different scopes and made different assumptions about key parameters (IPCC, 2001a). Globally, a 37 % reduction in CO_2 emissions by mid century compared to emissions today can be achieved. The accumulated CO_2 captured and stored globally can reach up to 240 billion ton CO_2 by 2050 (Stangeland, 2006).

IPCC's Third Assessment Report (IPCC, 2001b) found that the option for reducing emissions with most potential in the short term (up to 2020) was energy efficiency improvement while the near-term potential for CO_2 capture and storage was considered modest, amounting from 73 to 183 $MtCO_2$ per year (20 to 50 MtC per year) from coal and a similar amount from natural gas (see IPCC 2001a, Table TS.1). To meet IPCC's target on 50-80 % CO_2 emission reduction by 2050, a combination of increasing energy efficiency, switching from fossil fuel to renewable energy sources, and wide implementation of CCS is necessary (Stangeland, 2006). Nevertheless, faced with the longer-term climate challenge described above, and in view of the growing interest in this option, it has become important to analyze the potential of this technology in more depth.

As a result of the 2002 IPCC workshop on CO_2 capture and storage (IPCC, 2002), it is now recognized that the amount of CO_2 emissions which could potentially be captured and stored may be higher than the value given in the Third Assessment Report (ICPP, 2005). Indeed, the emissions reduction may be very significant compared with the values quoted above for the period after 2020. Wider use of this option may tend to restrict the opportunity to use other energy supply options. Nevertheless, such action might still lead to an increase in emissions abatement because much of the potential estimated previously (IPCC, 2001a) was from the application of measures concerned with end uses of energy. Some applications of CCS cost relatively little (for example, storage of CO_2 from gas processing as in the Sleipner project (Baklid *et al.*, 1996)) and this could allow them to be used at a relatively early date. Certain large industrial sources could present interesting low-cost opportunities for CCS, especially if combined with storage opportunities which generate compensating revenue, such as CO_2 Enhanced Oil Recovery (EOR) (IEA GHG, 2002).

1.7 Layout of the Report

This report is organized into eight chapters. Brief introduction with background information about the grounds on carbon dioxide (CO_2) capture and storage including the properties and health effects and sources of CO_2 as well as the context for capture and storage together with the potential for reducing atmospheric emissions is highlighted in this chapter. Chapter 2 gives detail on the geological framework for CO_2 storage. In this chapter, the historical perspectives of geological storage of CO_2, geological formations in general and the requirements in deep saline formations in particular with current and future geological storage projects are highlighted. Chapter 3 examines the geological storage mechanisms and storage security. Injection of CO_2 into the pore space and fractures of a permeable geological 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 chapter examines these processes and their influence on geological storage of CO_2. Site characterization and performance prediction are the topics covered in Chapter 4.

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[1]Economy in transition is an economy which is changing from a planned economy to a free market.

Key goals for geological CO_2 storage site characterization are to assess how much CO_2 can be stored at a potential storage site and to demonstrate that the site is capable of meeting required storage performance criteria. Site characterization requires the collection of the wide variety of geological data that are needed to achieve these goals. Much of the data will necessarily be site-specific. Most data will be integrated into geological models that will be used to simulate and predict the performance of the site. These and related issues are considered in chapter four in this report.

Chapter 5, details the monitoring and verification aspects of a geological CO_2 storage site. What actually happens to CO_2 in the subsurface and how do we know what is happening? In other words, can we monitor CO_2 once it is injected? What techniques are available for monitoring whether CO_2 is leaking out of the storage formation and how sensitive are they? Can we verify that CO_2 is safely and effectively stored underground? How long is monitoring needed? These questions are addressed in Chapter 5 of the report. Risk assessment, management and remediation of geological CO_2 storage are discussed in Chapter 6. What are the risks of storing CO_2 in deep geological formations? Can a geological storage site be operated safely? What are the safety concerns and environmental impact if a storage site leaks? Can a CO_2 storage site be fixed if something does go wrong? These questions are addressed in this chapter. After reviewing the current state of knowledge, the existing gaps in knowledge are also outlined.

The existing gaps in knowledge on the geological storage of CO_2 are detailed in Chapter 7. In Chapter 8 a case study from the Sleipner Gas field in Norway is presented. Background studies, geological suitability of the deep saline aquifer carbon dioxide storage and the tasks accomplished during the two phases of the Saline Aquifer Carbon dioxide Storage (SACS1/2) projects are detailed. Summary of recent studies at Sliepner, the geological security and environmental issues are also discussed in this chapter. Finally, these are followed by the conclusions drawn and the recommendations made from the study.

2 Geological Framework

2.1 Historical perspectives

Geological storage of CO_2 provide a way to avoid emitting CO_2 into the atmosphere, by capturing CO_2 from major stationary sources, transporting it usually by pipeline and injecting it into suitable deep rock formations. 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 grown from a concept of limited interest to one that is quite widely regarded as a potentially important mitigation option. There are several reasons for this. First, as research has progressed and as demonstration and commercial projects has 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.

2.2 Geological formations

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 2). 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 (Figure 3) and some adjacent deep-marine sedimentary basins are potential offshore storage sites, but the majority of sediments of the abyssal deep ocean floor (extreme right in Figure 3) are too thin and impermeable to be suitable for geological storage (Cook and Carleton, 2000). In addition to storage in sedimentary formations, some other geological formations which may serve as storage sites include caverns, basalt and organic-rich shales. In this study emphasis is given to deep saline aquifer formations (Section 2.2.2). Readers are referred to details in other geological formations in IPCC, 2005 report.

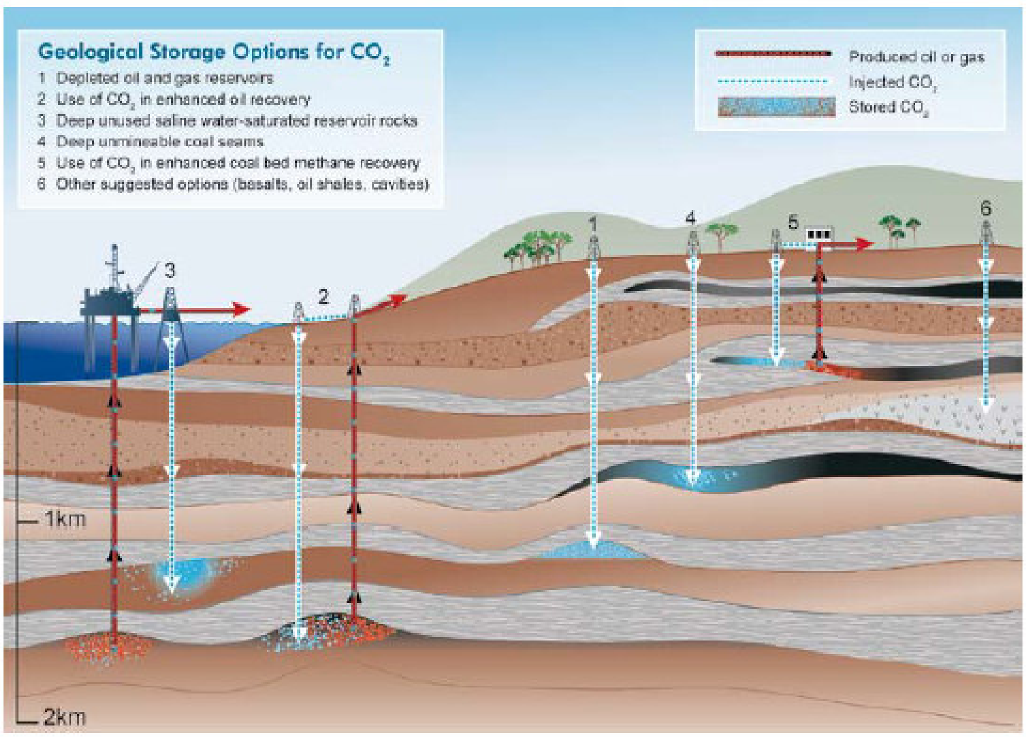

Figure 2: Options for storing CO_2 in deep underground geological formations (after Cook 1999, source IPCC 2005).

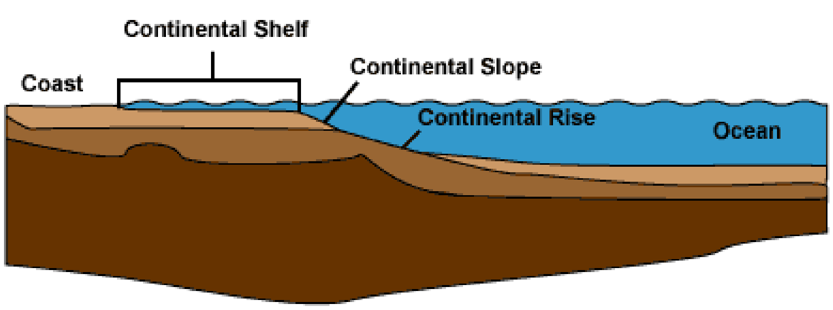

Figure 3: Block diagram showing ocean regions: ocean, continental margin and rise

2.2.1 *General requirements*

There are many sedimentary regions in the world (Figure 4) variously suited for CO_2 storage. In general, geological storage sites should have:

(1) Adequate capacity and injectivity,
(2) A satisfactory sealing caprock or confining unit and
(3) A sufficiently stable geological environment to avoid compromising the integrity of the storage site.

Criteria for assessing basin suitability (Bachu, 2000, 2003; Bradshaw *et al.*, 2002) include:

- basin characteristics (tectonic activity, sediment type, geothermal and hydrodynamic regimes)
- basin resources (hydrocarbons, coal, salt)
- industry maturity and infrastructure; and
- societal issues such as level of development, economy, environmental concerns, public education and attitudes.

The suitability of sedimentary basins for CO_2 storage depends in part on their location on the continental plate. Basins formed in mid-continent locations or near the edge of stable continental plates, are excellent targets for long-term CO_2 storage because of their stability and structure. Such basins are found within most continents and around the Atlantic, Arctic and Indian Oceans. The storage potential of basins found behind mountains formed by plate collision is likely to be good and these include the Rocky Mountain, Appalachian and Andean basins in the Americas, European basins immediately north of the Alps and Carpathians and west of the Urals and those located south of the Zagros and Himalayas in Asia.

Basins located in tectonically active areas, such as those around the Pacific Ocean or the northern Mediterranean may be less suitable for CO_2 storage and sites in these regions must be selected carefully because of the potential for CO_2 leakage (Chiodini *et al.*, 2001; Granieri *et al.*, 2003). Basins located on the edges of plates where subduction is occurring or between active mountain ranges, are likely to be strongly folded and faulted and provide less certainty for storage. However, basins must be assessed on an individual basis. For example, the Los Angeles Basin and Sacramento Valley in California, where significant hydrocarbon accumulations have been found, have demonstrated good local storage capacity. Poor CO_2 storage potential is likely to be exhibited by basins that

(1) are thin (≤1000 m)
(2) have poor reservoir and seal relationships
(3) are highly faulted and fractured
(4) are within fold belts
(5) have strongly discordant sequences
(6) have undergone significant diagenesis
(7) have over pressured reservoirs.

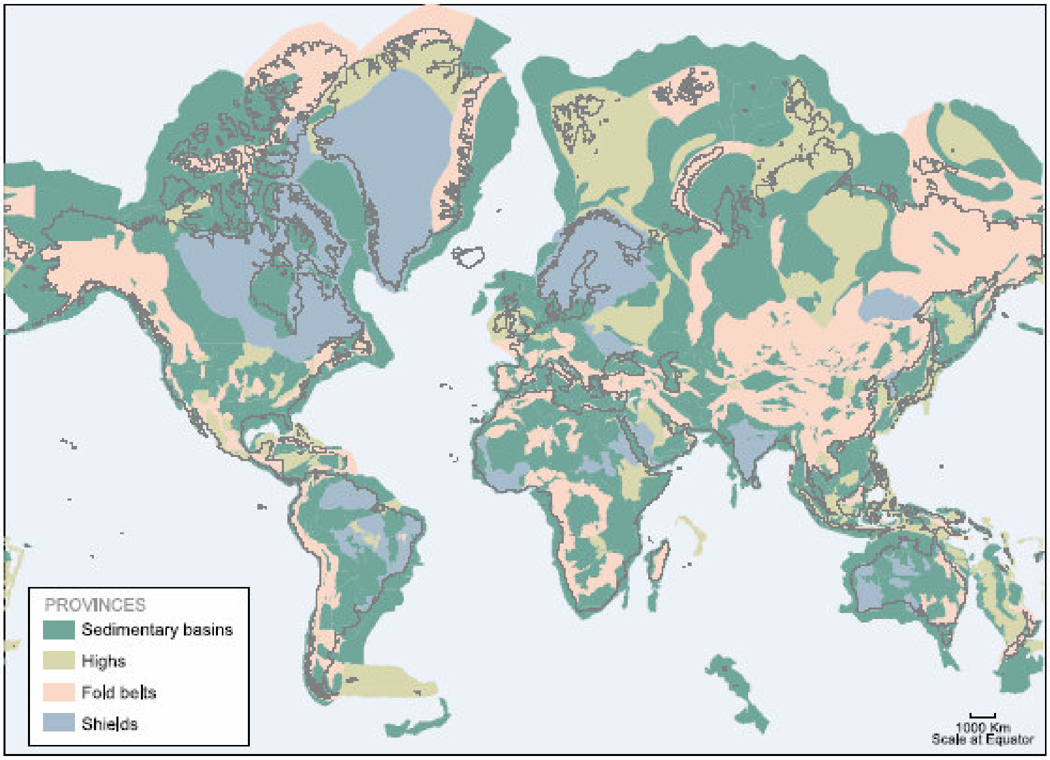

Figure 4: Distribution of sedimentary basins around the world (after Bradshaw and Dance, 2005; and USGS, 2001a). In general, sedimentary basins are likely to be the most prospective areas for storage sites. However, storage sites may also be found in some areas of fold belts and in some of the highs. Shield areas constitute regions with low prospectivity for storage.

Adequate porosity and thickness (for storage capacity) and permeability (for injectivity) are critical; porosity usually decreases with depth because of compaction and cementation, which reduces storage capacity and efficiency. The storage formation should be capped by extensive confining units (such as shale, salt or anhydrite beds) to ensure that CO_2 does not escape into overlying, shallower rock units and ultimately to the surface. Extensively faulted and fractured sedimentary basins or parts thereof, particularly in seismically active areas, require 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 over pressured by compaction and/or hydrocarbon generation may raise technological and safety issues that make them unsuitable. Under pressured 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.

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 by CO_2 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).

*2.2.2 **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 and details are presented in Chapter 8. The saline water from the Utsira formation is used for water injection in deeper reservoirs.

2.3 Geological storage

To geologically store CO_2, it must first be compressed, usually to a dense fluid state known as 'supercritical'. Supercritical means at a temperature and pressure above the critical temperature and pressure of the substance concerned (carbon dioxide) (at temperatures higher than 31.1^{o}C and the pressure is greater than 73.9 bar). The critical point represents the highest temperature and pressure at which the substance can exist as a vapour and liquid in equilibrium. 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).

The efficiency of CO_2 storage in geological media, defined as the amount of CO_2 stored per unit volume (Brennan and Burruss, 2003), increases with increasing CO_2 density. Storage safety also increases with increasing density, because buoyancy, which drives upward migration, is stronger for a lighter fluid. Density increases significantly with depth while CO_2 is in gaseous phase, increases only slightly or levels off after passing from the gaseous phase

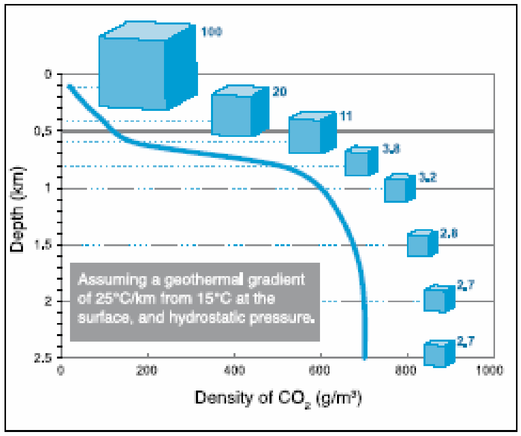

Figure 5: Variation of CO_2 density with depth, assuming hydrostatic pressure and a geothermal gradient of 25°C km–1 from 15°C at the surface (based on the density data of Angus *et al.*, 1973). Carbon dioxide density increases rapidly at approximately 800 m depth, when the CO_2 reaches a supercritical 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.

into the dense phase and may even decrease with a further increase in depth, depending on the temperature gradient (Ennis-King and Paterson, 2001; Bachu, 2003). 'Cold' sedimentary basins, characterized by low temperature gradients, are more favourable for CO_2 storage (Bachu, 2003) because CO_2 attains higher density at shallower depths (700–1000 m) than in 'warm' sedimentary basins, characterized by high temperature gradients where dense-fluid conditions are reached at greater depths (1000–1500 m). The depth of the storage formation (leading to increased drilling and compression costs for deeper formations) may also influence the selection of storage sites.

Depending on the type of the geological formations, geological storage is commonly limited by a number of determining factors. The most common in abandoned oil and gas fields and saline formations is the capacity of a reservoir will be limited by the need to avoid exceeding pressures that damage the caprock. 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.*, 2002). 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.

Reservoir heterogeneity also affects CO_2 storage efficiency. The density difference between the lighter CO_2 and the reservoir oil and/or saline 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).

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. 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.

*2.3.1 **Effects of impurities***

The presence of impurities in the CO_2 gas stream affects the engineering processes of capture, transport and injection, 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 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 3.4.2) 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.

*2.3.2 **Storage in deep saline formations***

Saline formations occur in sedimentary basins throughout the world, both onshore and on the continental shelves and are not limited to hydrocarbon provinces or coal basins. However, estimating the CO_2 storage capacity of deep saline formations is presently a challenge for the following reasons:

- There are multiple mechanisms for storage, including physical trapping beneath low permeability caprock (seal), dissolution and mineralization;
- These mechanisms operate both simultaneously and on different time scales, such that the time frame of CO_2 storage affects the capacity estimate; volumetric storage is important initially, but later CO_2 dissolves and reacts with minerals;
- Relations and interactions between these various mechanisms are very complex, evolve with time and are highly dependent on local conditions;
- There is no single, consistent, broadly available methodology for estimating CO_2 storage capacity (various studies have used different methods that do not allow comparison).
- Only limited seismic and well data are normally available (unlike data on oil and gas reservoirs).

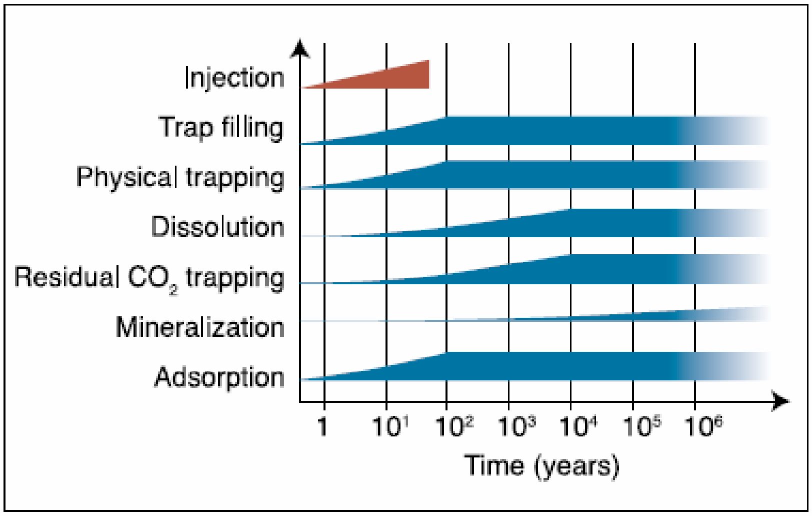

Figure 6: Schematic showing the time evolution of various CO_2 storage mechanisms operating in deep saline formations, during and after injection. Assessing storage capacity is complicated by the different time and spatial scales over which these processes occur (source IPCC, 2005).

To understand the difficulties in assessing CO_2 storage capacity in deep saline formations, we need to understand the interplay of the various trapping mechanisms during the evolution of a CO_2 plume (Section 3.2 and Figure 6). In addition, the storage capacity of deep saline formations can be determined only on a case-by-case basis.

To date, most of the estimates of CO_2 storage capacity in deep saline formations focus on physical trapping and/or dissolution. These estimates make the simplifying assumption that no geochemical reactions take place concurrent with CO_2 injection, flow and dissolution. Some recent work suggests that it can take several thousand years for geochemical reactions to have a significant impact (Xu *et al.*, 2003). More than 14 global assessments of capacity have been made by using these types of approaches (IEA-GHG, 2004). The range of estimates from these studies is large (200–56,000 $GtCO_2$), reflecting both the different assumptions used to make these estimates and the uncertainty in the parameters. Most of the estimates are in the range of several hundred Gtonnes of CO_2. More detailed regional and local capacity assessments are required to resolve this issue.

2.4 Existing and planned CO_2 projects

A number of pilot and commercial CO_2 storage projects are under way or proposed (Figure 7). 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, Snøhvit in the Barents Sea, In Salah in Algeria and Gorgon in Australia (Figure 7), as well as the acid gas injection projects in Canada and the United States. At the Sleipner Project, operated by Statoil, about 10 Mt CO_2 (at injection rate of 1 Mt CO_2 per year) has been injected into a deep subsea saline formation since 1996 (Chapter 8). The CO_2 content in the natural gas varies from 4 to 9.5 % and the CO_2 content has to be reduced below 2,5% for export quality. Existing and planned storage projects are also listed in Table 2.

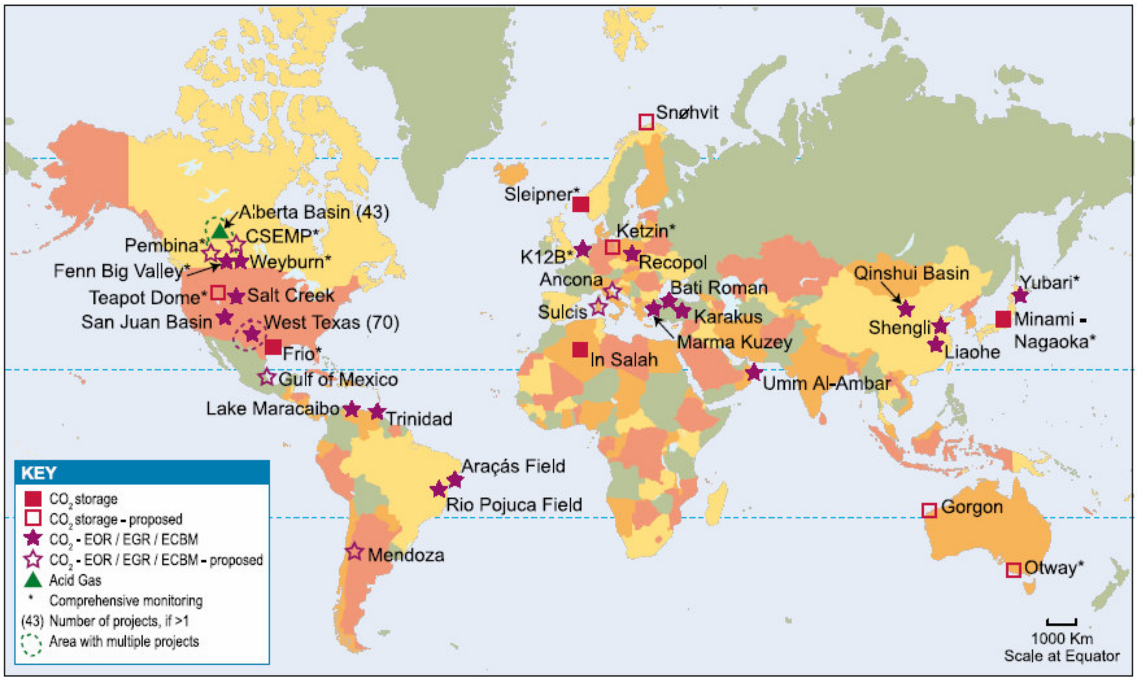

Figure 7: Location of sites where activities relevant to CO_2 storage are planned or under way (IPCC, 2005).

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. Statoil is planning another project in the Barents Sea, where CO_2 from the Snøhvit 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.

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

Table 2. A selection of current and planned geological storage projects (IPCC, 2005).

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	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 Univ. of Texas	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	2007	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	Comprehesive

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 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. The project is expected to inject 23 $MtCO_2$ and extend the life of the oil field by 25 years (Moberg *et al.*, 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 7 and Table 2). 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. Moreover there are many announced projects: BP to capture CO_2 from a power plant in Peterhead, Scotland and transport it to the Miller oil field in the North Sea for EOR. Statoil and Shell planning a new natural gas fired power plant at Tjeldbergodden, Norway with CO_2 capture. CO_2 will be transported to the Draugen and Heidrun oil field and used for EOR. CO_2 capture planned at a new natural gas fired power plant at Kårstø, Norway for EOR use and at Esbjerg in Denmark. The numbers of CO_2 capture and storage projects which have already been announced also demonstrate the confidence in this technology.

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). Further CO_2-ECBM[3] 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). All these projects mentioned demonstrate that subsurface injection of CO_2 is not for the distant future, but is being implemented now for environmental and/or commercial reasons.

[3]ECBM - Enhanced coal bed methane recovery; the use of CO2 to enhance the recovery of the methane present in unminable coal beds through the preferential adsorption of CO2 on coal.

3 Storage mechanisms and storage security

3.1 CO_2 flow and transport processes

Injection of fluids into deep geological formations is achieved by pumping fluids down into a well. 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 build-up 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. Because supercritical CO_2 is much less viscous (flows more easily) 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 (flows less easily) 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 saline formations and oil reservoirs, the buoyant plume of injected CO_2 migrates upwards, but not evenly. This is because a lower permeability layer acts as a barrier and causes the CO_2 to migrate laterally, filling any stratigraphic or structural trap it encounters. The shape of the CO_2 plume rising through the rock matrix (Figure 8) is strongly affected by formation heterogeneity, such as low-permeability shale lenses (Flett *et al.*, 2005). Low-permeability layers within the storage formation therefore have the effect of slowing the upward migration of CO_2, which would otherwise cause CO_2 to bypass deeper parts of the storage formation (Doughty *et al.*, 2001).

As CO_2 migrates through the formation, some of it will dissolve into the formation water. In systems with slowly flowing water, reservoir-scale numerical simulations show that, over tens of years, a significant amount, up to 30% of the injected CO_2, will dissolve in formation water (Doughty *et al.*, 2001). Basin-scale simulations suggest that over centuries, the entire CO_2 plume dissolves in formation water (McPherson and Cole, 2000; Ennis-King *et al.*, 2003). If the injected CO_2 is contained in a closed structure (no flow of formation water), it will take much longer for CO_2 to completely dissolve because of reduced contact with unsaturated formation water. Once CO_2 is dissolved in the formation fluid, it migrates along with the regional groundwater flow. For deep sedimentary basins characterized by low permeability and high salinity, groundwater flow velocities are very low, typically on the order of millimetres to centimetres per year (Bachu *et al.*, 1994). Thus, migration rates of dissolved CO_2 are substantially lower than for separate-phase CO_2.

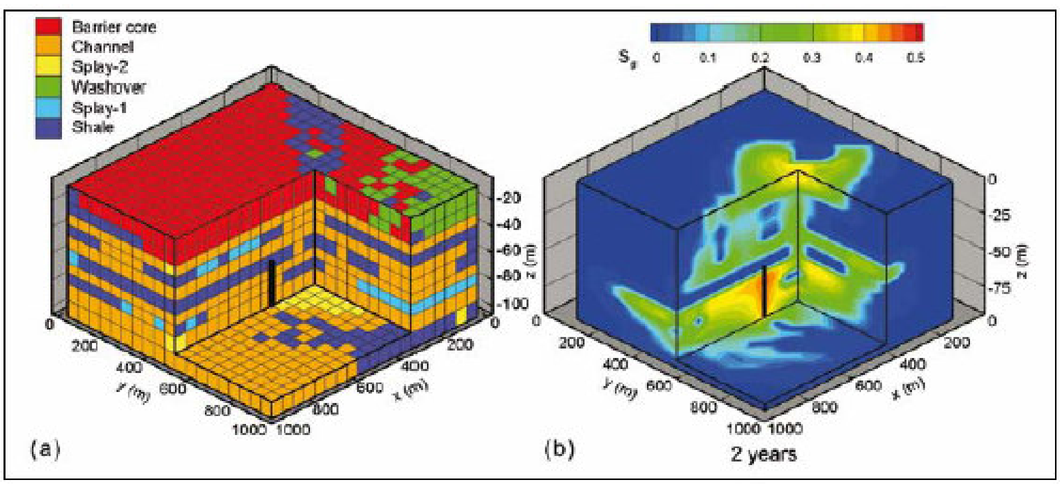

Figure 8 Simulated distribution of CO_2 injected into a heterogeneous formation with low-permeability layers that block upward migration of CO_2. (a) Illustration of a heterogeneous formation facies grid model. The location of the injection well is indicated by the vertical line in the lower portion of the grid. (b) The CO_2 distribution after two years of injection. Note that the simulated distribution of CO_2 is strongly influenced by the low-permeability layers that block and delay upward movement of CO_2 (after Doughty and Pruess, 2004).

Water saturated with CO_2 is slightly denser (approximately 1%) than the original formation water, depending on salinity (Enick and Klara, 1990; Bachu and Adams, 2003). With high vertical permeability, this may lead to free convection, replacing the CO_2-saturated water from the plume vicinity with unsaturated water, producing faster rates of CO_2 dissolution (Lindeberg and Wessel-Berg, 1997; Ennis-King and Paterson, 2003). Figure 9 illustrates the formation of convection cells and dissolution of CO_2 over several thousand years. The solubility of CO_2 in brine decreases with increasing pressure, decreasing temperature and increasing salinity. Calculations indicate that, depending on the salinity and depth, 20–60 kg CO_2 can dissolve in 1 m^3 of formation fluid (Holt *et al.*, 1995; Koide *et al.*, 1995). With the use of a homogeneous model rather than a heterogeneous one, the time required for complete CO_2 dissolution may be underestimated.

As CO_2 migrates through a formation, some of it is retained in the pore space by capillary forces (Figure 8), commonly referred to as 'residual CO_2 trapping', which may immobilize significant amounts of CO_2 (Obdam *et al.*, 2003; Kumar *et al.*, 2005). Figure 10 illustrates that when the degree of trapping is high and CO_2 is injected at the bottom of a thick formation, all of the CO_2 may be trapped by this mechanism, even before it reaches the caprock at the top of the formation. While this effect is formation-specific, Holtz (2002) has demonstrated that residual CO_2 saturations may be as high as 15–25% for many typical storage formations. Over time, much of the trapped CO_2 dissolves in the formation water (Ennis-King and Paterson, 2003), although appropriate reservoir engineering can accelerate or modify solubility trapping (Keith *et al.*, 2005).

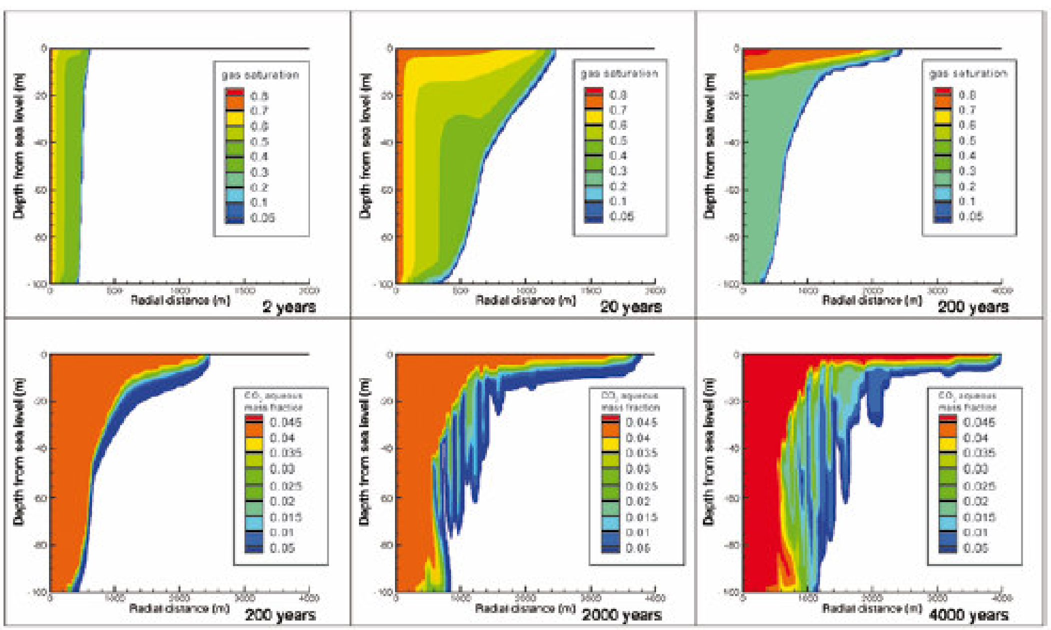

Figure 9 Radial simulations of CO_2 injection into a homogeneous formation 100 m thick, at a depth of 1 km, where the pressure is 10 MPa and the temperature is 40°C. The injection rate is 1 $MtCO_2$ yr-1 for 20 years, the horizontal permeability is 10 –13 m2 (approximately 100 mD) and the vertical permeability is one-tenth of that. The residual CO_2 saturation is 20%. The first three parts of the figure at 2, 20 and 200 years, show the gas saturation in the porous medium; the second three parts of the figure at 200, 2000 and 4000 years, show the mass fraction of dissolved CO_2 in the aqueous phase (after Ennis-King and Paterson, 2003).

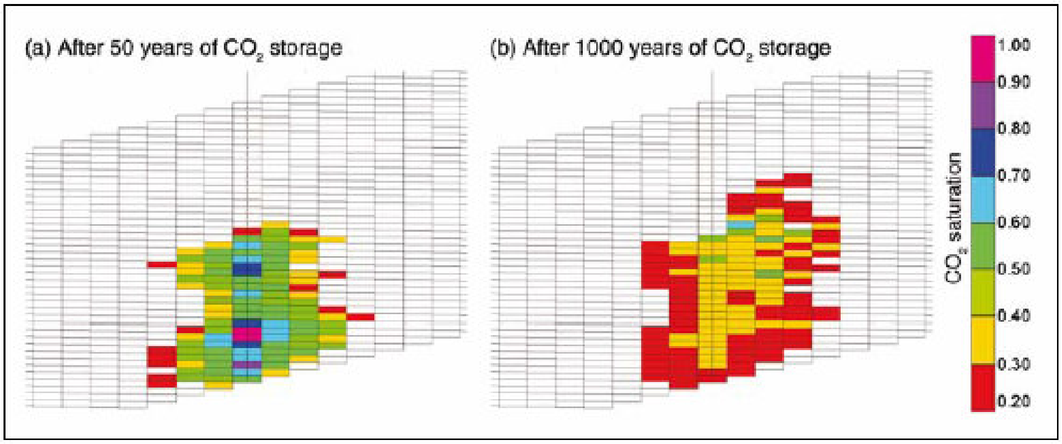

Figure 10 Simulation of 50 years of injection of CO_2 into the base of a saline formation. Capillary forces trap CO_2 in the pore spaces of sedimentary rocks. (a) After the 50-year injection period, most CO_2 is still mobile, driven upwards by buoyancy forces. (b) After 1000 years, buoyancy-driven flow has expanded the volume affected by CO_2 and much is trapped as residual CO_2 saturation or dissolved in brine (not shown). Little CO_2 is mobile and all CO_2 is contained within the aquifer (after Kumar et al., 2005).

3.2 CO_2 storage mechanisms in geological formations

The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms (Figure 11). The most effective storage sites are those where CO_2 is immobile because it is trapped permanently under a thick, low-permeability seal or is converted to solid minerals or is adsorbed on the surfaces of coal micropores or through a combination of physical and chemical trapping mechanisms.

3.2.1 Physical trapping: stratigraphic and structural

Initially, physical trapping of CO_2 below low-permeability seals (caprocks), such as very-low-permeability shale or salt beds, is the principal means to store CO_2 in geological formations (Figure 2). In some high latitude areas, shallow gas hydrates may conceivably act as a seal. Sedimentary basins have such closed, physically bound traps or structures, which are occupied mainly by saline water, oil and gas. Structural traps include those formed by folded or fractured rocks. Faults can act as permeability barriers in some circumstances and as preferential pathways for fluid flow in other circumstances (Salvi *et al.*, 2000). Stratigraphic traps are formed by changes in rock type caused by variation in the setting where the rocks were deposited. Both of these types of traps are suitable for CO_2 storage, although, care must be taken not to exceed the allowable overpressure to avoid fracturing the caprock or re-activating faults (Streit *et al.*, 2005).

3.2.2 Physical trapping: hydrodynamic

Hydrodynamic trapping can occur in saline formations that do not have a closed trap, but where fluids migrate very slowly over long distances. When CO_2 is injected into a formation, it displaces saline formation water and then migrates buoyantly upwards, because it is less dense than the water. When it reaches the top of the formation, it continues to migrate as a

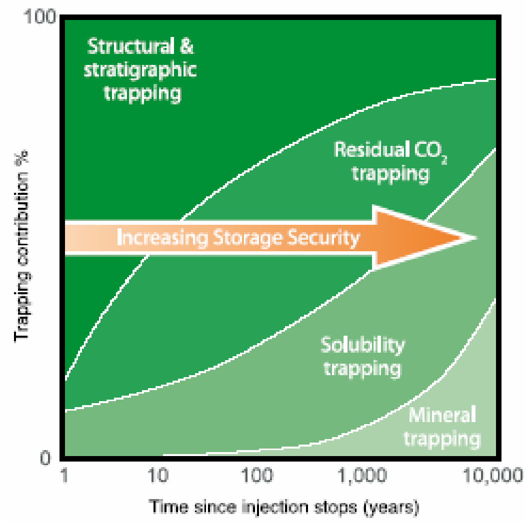

Figure 11 Storage securities depend on a combination of physical and geochemical trapping. Over time, the physical process of residual CO_2 trapping and geochemical processes of solubility trapping and mineral trapping increase (IPCC, 2005).

separate phase until it is trapped as residual CO_2 saturation or in local structural or stratigraphic traps within the sealing formation. In the longer term, significant quantities of CO_2 dissolve in the formation water and then migrate with the groundwater. Where the distance from the deep injection site to the end of the overlying impermeable formation is hundreds of kilometres, the time scale for fluid to reach the surface from the deep basin can be millions of years (Bachu *et al.*, 1994).

3.2.3 Geochemical trapping

Carbon dioxide in the subsurface can undergo a sequence of geochemical interactions with the rock and formation water that will further increase storage capacity and effectiveness. First, when CO_2 dissolves in formation water, a process commonly called solubility trapping occurs. The primary benefit of solubility trapping is that once CO_2 is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upwards. Next, it will form ionic species as the rock dissolves, accompanied by a rise in the pH. Finally, some fraction may be converted to stable carbonate minerals (mineral trapping), the most permanent form of geological storage (Gunter *et al.*, 1993). Mineral trapping is believed to be comparatively slow, potentially taking a thousand years or longer. Nevertheless, the permanence of mineral storage, combined with the potentially large storage capacity present in some geological settings, makes this a desirable feature of long-term storage.

Dissolution of CO_2 in formation waters can be represented by the chemical reaction:

$$CO_2\,(g) + H_2O \leftrightarrow H_2CO_3 \leftrightarrow HCO_3^{\,-} + H^+ \leftrightarrow CO_3^{\,2-} + 2H^+$$

The CO_2 solubility in formation water decreases as temperature and salinity increase. Dissolution is rapid when formation water and CO_2 share the same pore space, but once the formation fluid is saturated with CO_2, the rate slows and is controlled by diffusion and convection rates.

CO_2 dissolved in water produces a weak acid, which reacts with the sodium and potassium basic silicate or calcium, magnesium and iron carbonate or silicate minerals in the reservoir or formation to form bicarbonate ions by chemical reactions approximating to:

$$3 \text{ K-feldspar} + 2H_2O + 2CO_2 \leftrightarrow \text{Muscovite} + 6 \text{ Quartz} + 2K^+ + 2HCO_3^-$$

Reaction of the dissolved CO_2 with minerals can be rapid (days) in the case of some carbonate minerals, but slow (hundreds to thousands of years) in the case of silicate minerals.

Formation of carbonate minerals occurs from continued reaction of the bicarbonate ions with calcium, magnesium and iron from silicate minerals such as clays, micas, chlorites and feldspars present in the rock matrix (Gunter *et al.*, 1993, 1997).

Perkins *et al.* (2005) estimate that over 5000 years, all the CO_2 injected into the Weyburn Oil Field will dissolve or be converted to carbonate minerals within the storage formation. Equally importantly, they show that the caprock and overlying rock formations have an even greater capacity for mineralization. This is significant for leakage risk assessment (Chapter 6) because once CO_2 is dissolved; it is unavailable for leakage as a discrete phase. Modelling by Holtz (2002) suggests more than 60% of CO_2 is trapped by residual CO_2 trapping by the end of the injection phase (100% after 1000 years), although laboratory experiments (Section 3.1) suggest somewhat lower percentages. When CO_2 is trapped at residual saturation, it is effectively immobile. However, should there be leakage through the caprock, then saturated brine may degas as it is depressurized, although, as illustrated in Figure 8 the tendency of saturated brine is to sink rather than to rise. Reaction of the CO_2 with formation water and rocks may result in reaction products that affect the porosity of the rock and the flow of solution through the pores. This possibility has not, however, been observed experimentally and its possible effects cannot be quantified.

3.3 Natural geological accumulations of CO_2

Natural sources of CO_2 occur, as gaseous accumulations of CO_2, CO_2 mixed with natural gas and CO_2 dissolved in formation water (Figure 12). These natural accumulations have been studied in the United States, Australia and Europe (Pearce *et al.*, 1996; Allis *et al.*, 2001; Stevens *et al.*, 2003; Watson *et al.*, 2004) as analogues for storage of CO_2, as well as for leakage from engineered storage sites. Production of CO_2 for EOR and other uses provides operational experience relevant to CO_2 capture and storage. There are, of course, differences between natural accumulations of CO_2 and engineered CO_2 storage sites: natural accumulations of CO_2 collect over very long periods of time and at random sites, some of which might be naturally 'leaky'. At engineered sites, CO_2 injection rates will be rapid and the sites will necessarily be penetrated by injection wells (Celia and Bachu, 2003; Johnson *et al.*, 2005). Therefore, care must be taken to keep injection pressures low enough to avoid damaging the caprock and to make sure that the wells are properly sealed.

Natural accumulations of relatively pure CO_2 are found all over the world in a range of geological settings, particularly in sedimentary basins, intra-plate volcanic regions (Figure 12) and in faulted areas or in quiescent volcanic structures. Natural accumulations occur in a number of different types of sedimentary rocks, principally limestones, dolomites and sandstones and with a variety of seals (mudstone, shale, salt and anhydrite) and a range of trap types, reservoir depths and CO_2-bearing phases.

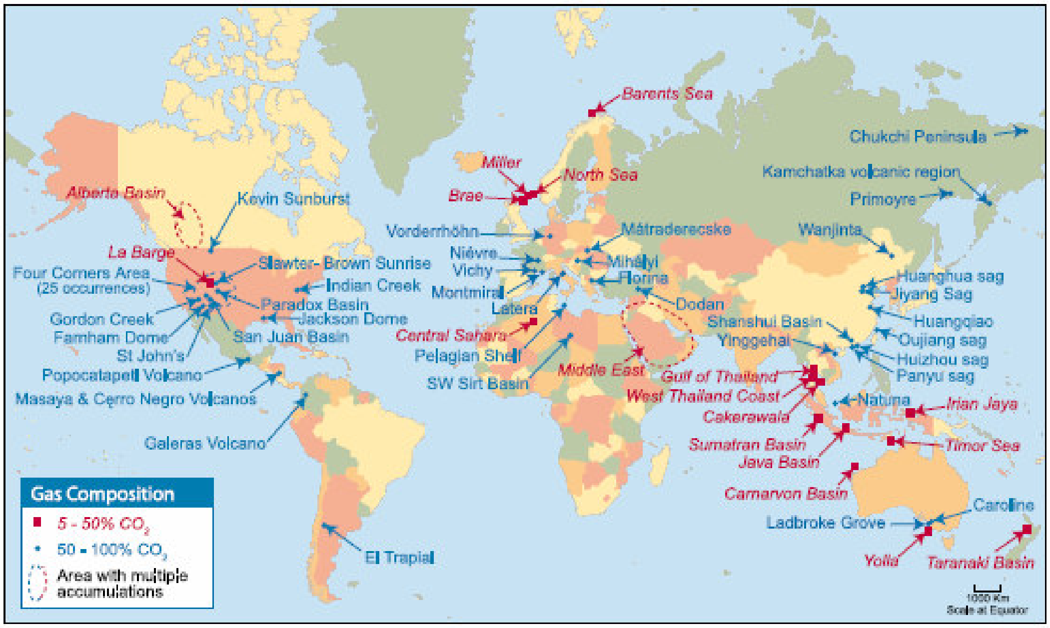

Figure 12 Examples of natural accumulations of CO2 around the world. Regions containing many occurrences are enclosed by a dashed line. Natural accumulations can be useful as analogues for certain aspects of storage and for assessing the environmental impacts of leakage. Data quality is variable and the apparent absence of accumulations in South America, southern Africa and central and northern Asia is probably more a reflection of lack of data than a lack of CO2 accumulations (IPCC, 2005).

Carbon dioxide fields in the Colorado Plateau and Rocky Mountains, USA, are comparable to conventional natural gas reservoirs (Allis *et al.*, 2001). Studies of three of these fields (McElmo Dome, St. Johns Field and Jackson Dome) have shown that each contains 1600 $MtCO_2$, with measurable leakage (Stevens *et al.*, 2001a). Two hundred Mt trapped in the Pisgah Anticline, northeast of the Jackson Dome, is thought to have been generated more than 65 million years ago (Studlick *et al.*, 1990), with no evidence of leakage, providing additional evidence of long-term trapping of CO_2. Extensive studies have been undertaken on small-scale CO_2 accumulations in the Otway Basin in Australia (Watson *et al.*, 2004) and in France, Germany, Hungary and Greece (Pearce *et al.*, 2003).

Conversely, some systems, typically spas and volcanic systems are leaky and not useful analogues for geological storage. The Kileaua Volcano emits on average 4 $MtCO_2$ yr^{-1}. More than 1200 tCO_2 day^{-1} (438,000 tCO_2 yr^{-1}) leaked into the Mammoth Mountain area, California, between 1990 and 1995, with flux variations linked to seismicity (USGS, 2001b). Average flux densities of 80–160 tCO_2 m^{-2} yr^{-1} are observed near Matraderecske, Hungary, but along faults, the flux density can reach approximately 6600 t m^{-2} yr^{-1} (Pearce *et al.*, 2003). These high seepage rates result from release of CO_2 from faulted volcanic systems, whereas a normal baseline CO_2 flux is of the order of 10–100 gCO_2 m^{-2} yr^{-1} under temperate climate conditions (Pizzino *et al.*, 2002). Seepage of CO_2 into Lake Nyos (Cameroon) resulted in CO_2 saturation of water deep in the lake, which in 1987 produced a very large-scale and (for more than 1700 persons) ultimately fatal release of CO_2 when the lake overturned (Kling *et al.*, 1987). The overturn of Lake Nyos (a deep, stratified tropical lake) and release of CO_2 are not representative of the seepage through wells or fractures that may occur from underground geological storage sites. Engineered CO_2 storage sites will be chosen to minimize the prospect of leakage. Natural storage and events such as Lake Nyos are not representative of geological storage for predicting seepage from engineered sites, but can be useful for studying the health, safety and environmental effects of CO_2 leakage.

Carbon dioxide is found in some oil and gas fields as a separate gas phase or dissolved in oil. This type of storage is relatively common in Southeast Asia, China and Australia, less common in other oil and gas provinces such as in Algeria, Russia, the Paradox Basin (USA) and the Alberta Basin (western Canada). In the North Sea and Barents Sea, a few fields have up to 10% CO_2, including Sleipner and Snøhvit (Figure 12). The La Barge natural gas field in Wyoming, USA, has 3300 Mt of gas reserves, with an average of 65% CO_2 by volume. In the Appennine region of Italy, many deep wells (1–3 km depth) have trapped gas containing 90% or more CO_2 by volume. Major CO_2 accumulations around the South China Sea include the world's largest known CO_2 accumulation, the Natuna D Alpha field in Indonesia, with more than 9100 $MtCO_2$ and 720 Mt natural gas. Concentrations of CO_2 can be highly variable between different fields in a basin and between different reservoir zones within the same field, reflecting complex generation, migration and mixing processes. In Australia's Otway Basin, the timing of CO_2 input and trapping ranges from 5000 years to a million years (Watson *et al.*, 2004).

3.4 Industrial analogues for CO_2 storage

3.4.1 Natural gas storage

Underground natural gas storage projects that offer experience relevant to CO_2 storage (Lippmann and Benson, 2003; Perry, 2005) have operated successfully for almost 100 years and in many parts of the world (Figure 13). These projects provide for peak loads and balance seasonal fluctuations in gas supply and demand. The majority of gas storage projects are in depleted oil and gas reservoirs and saline formations, although caverns in salt have also been used extensively. A number of factors are critical to the success of these projects, including a suitable and adequately characterized site (permeability, thickness and extent of storage reservoir, tightness of caprock, geological structure, lithology, etc.). Injection wells must be properly designed, installed, monitored and maintained and abandoned wells in and near the project must be located and plugged. Finally, taking into account a range of solubility, density and trapping conditions, over pressuring the storage reservoir (injecting gas at a pressure that is well in excess of the in situ formation pressure) must be avoided.

While underground natural gas storage is safe and effective, some projects have leaked, mostly caused by poorly completed or improperly plugged and abandoned wells and by leaky faults (Gurevich *et al.*, 1993; Lippmann and Benson, 2003; Perry, 2005). Abandoned oil and gas fields are easier to assess as natural gas storage sites than are saline formations, because the geological structure and caprock are usually well characterized from existing wells. At most natural gas storage sites, monitoring requirements focus on ensuring that the injection well is not leaking (by the use of pressure measurements and through *in situ* downhole measurements of temperature, pressure, noise/sonic, casing conditions, etc.). Observation wells are sometimes used to verify that gas has not leaked into shallower strata.

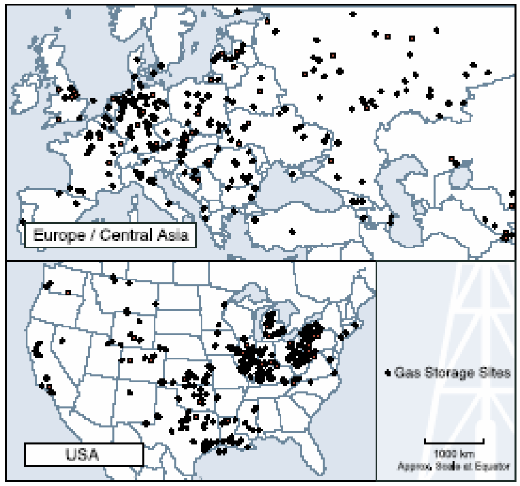

Figure 13 Location of some natural gas storage projects (IPCC, 2005).

3.4.2 Acid gas injection

Acid gas injection operations represent a commercial analogue for some aspects of geological CO_2 storage. Acid gas is a mixture of H_2S and CO_2, with minor amounts of hydrocarbon gases that can result from petroleum production or processing. In Western Canada, operators are increasingly turning to acid gas disposal by injection into deep geological formations. Although the purpose of the acid gas injection operations is to dispose of H_2S, significant quantities of CO_2 are injected at the same time because it is uneconomic to separate the two gases.

Currently, regulatory agencies in Western Canada approve the maximum H_2S fraction, maximum wellhead injection pressure and rate and maximum injection volume. Acid gas is currently injected into 51 different formations at 44 different locations across the Alberta Basin in the provinces of Alberta and British Columbia (Figure 14). Carbon dioxide often represents the largest component of the injected acid gas stream, in many cases, 14–98% of the total volume. A total of 2.5 $MtCO_2$ and 2 MtH_2S had been injected in Western Canada by the end of 2003, at rates of 840–500,720 m3 day^{-1} per site, with an aggregate injection rate in 2003 of 0.45 $MtCO_2$ yr^{-1} and 0.55 MtH_2S yr^{-1}, with no detectable leakage.

Acid gas injection in Western Canada occurs over a wide range of formation and reservoir types, acid gas compositions and operating conditions. Injection takes place in deep saline formations at 27 sites, into depleted oil and/or gas reservoirs at 19 sites and into the underlying water leg of depleted oil and gas reservoirs at 4 sites. Carbonates form the reservoir at 29 sites and quartz-rich sandstones dominate at the remaining 21 (Figure 14). In most cases, shale constitutes the overlying confining unit (caprock), with the remainder of the injection zones being confined by tight limestones, evaporites and anhydrites.

Since the first acid-gas injection operation in 1990, 51 different injection sites have been approved, of which 44 are currently active. One operation was not implemented, three were rescinded after a period of operation (either because injection volumes reached the approved limit or because the gas plant producing the acid gas was decommissioned) and three sites were suspended by the regulatory agency because of reservoir over pressuring.

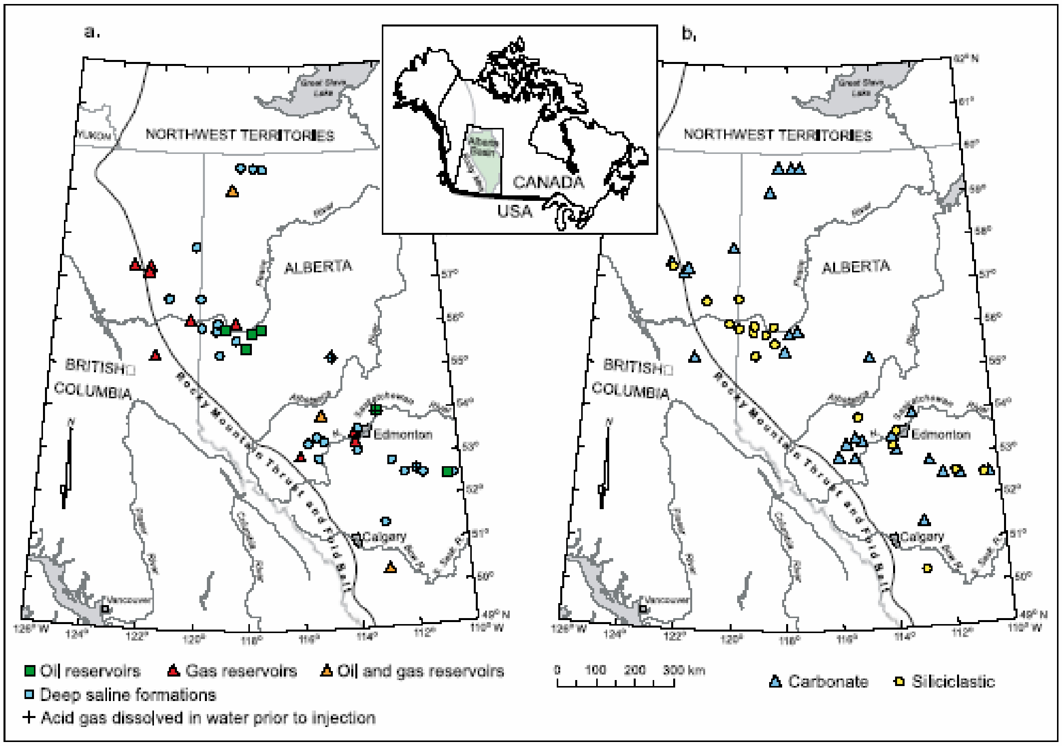

Figure 14 Locations of acid gas injection sites in the Alberta Basin, Canada: (a) classified by injection unit; (b) the same locations classified by rock type (from Bachu and Haug, 2005).

3.4.3 Liquid waste injection

In many parts of the world, large volumes of liquid waste are injected into the deep subsurface every day. For example, for the past 60 years, approximately 9 billion gallons (34.1 million m^3) of hazardous waste is injected into saline formations in the United States from about 500 wells each year. In addition, more than 750 billion gallons (2843 million m^3) of oil field brines are injected from 150,000 wells each year. This combined annual US injectate volume of about 3000 million m^3, when converted to volume equivalent, corresponds to the volume of approximately 2 $GtCO_2$ at a depth of 1 km. Therefore, the experience gained from existing deep-fluid-injection projects is relevant in terms of the style of operation and is of a similar magnitude to that which may be required for geological storage of CO_2.

3.5 Security and duration of CO_2 storage in geological formations

Evidence from oil and gas fields indicates that hydrocarbons and other gases and fluids including CO_2 can remain trapped for millions of years (Magoon and Dow, 1994; Bradshaw *et al.*, 2005). Carbon dioxide has a tendency to remain in the subsurface (relative to hydrocarbons) via its many physicochemical immobilization mechanisms. World-class petroleum provinces have storage times for oil and gas of 5–100 million years, others for 350 million years, while some minor petroleum accumulations have been stored for up to 1400 million years. However, some natural traps do leak, which reinforces the need for careful site selection, characterization and injection practices.

4 Site characterization and performance prediction

4.1 Site characterization

Storage site requirements depend greatly upon the trapping mechanism and the geological medium in which storage is proposed (e.g., deep saline formation, depleted oil or gas field or coal seam). Data availability and quality vary greatly between each of these options. In many cases, oil and gas fields will be better characterized than deep saline formations because a relevant data set was collected during hydrocarbon exploration and production. However, this may not always be the case. There are many examples of deep saline formations whose character and performance for CO_2 storage can be predicted reliably over a large area (Chadwick *et al.*, 2003; Bradshaw *et al.*, 2003).

4.1.1 ***Data types***

The storage site and its surroundings need to be characterized in terms of geology, hydrogeology, geochemistry and geomechanics (structural geology and deformation in response to stress changes). The greatest emphasis will be placed on the reservoir and its sealing horizons. However, the strata above the storage formation and caprock also need to be assessed because if CO_2 leaked it would migrate through them (Haidl *et al.*, 2005). Documentation of the characteristics of any particular storage site will rely on data that have been obtained directly from the reservoir, such as core and fluids produced from wells at or near the proposed storage site, pressure transient tests conducted to test seal efficiency and indirect remote sensing measurements such as seismic reflection data and regional hydrodynamic pressure gradients. Integration of all of the different types of data is needed to develop a reliable model that can be used to assess whether a site is suitable for CO_2 storage.

During the site-selection process that may follow an initial screening, detailed reservoir simulation (Section 4.2) will be necessary to meaningfully assess a potential storage site. A range of geophysical, geological, hydrogeological and geomechanical information is required to perform the modelling associated with a reservoir simulation. This information must be built into a three-dimensional geological model, populated with known and extrapolated data at an appropriate scale.

Financial constraints may limit the types of data that can be collected as part of the site characterization and selection process. Today, no standard methodology prescribes how a site must be characterized. Instead, selections about site characterization data will be made on a site-specific basis, choosing those data sets that will be most valuable in the particular geological setting. However, some data sets are likely to be selected for every case. Geological site description from well bores and outcrops are needed to characterize the storage formation and seal properties. Seismic surveys are needed to define the subsurface geological structure and identify faults or fractures that could create leakage pathways. Formation pressure measurements are needed to map the rate and direction of groundwater flow. Water quality samples are needed to demonstrate the isolation between deep and shallow groundwater.

4.1.2 Assessment of stratigraphic factors affecting site integrity

Caprocks or seals are the permeability barriers (mostly vertical but sometimes lateral) that prevent or impede migration of CO_2 from the injection site. The integrity of a seal depends on spatial distribution and physical properties. Ideally, a sealing rock unit should be regional in nature and uniform in lithology, especially at its base. Where there are lateral changes in the basal units of a seal rock, the chance of migration out of the primary reservoir into higher intervals increases. However, if the seal rock is uniform, regionally extensive and thick, then the main issues will be the physical rock strength, any natural or anthropomorphic penetrations (faults, fractures and wells) and potential CO_2-water-rock reactions that could weaken the seal rock or increase its porosity and permeability.

Methods have been described for making field-scale measurements of the permeability of caprocks for formation gas storage projects, based on theoretical developments in the 1950s and 1960s (Hantush and Jacobs, 1955; Hantush, 1960). These use water-pumping tests to measure the rate of leakage across the caprock (Witherspoon *et al.*, 1968). A related type of test, called a pressure 'leak-off' test, can be used to measure caprock permeability and *in situ* stress. The capacity of a seal rock to hold back fluids can also be estimated from core samples by mercury injection capillary pressure (MICP) analysis, a method widely used in the oil and gas industry (Vavra *et al.*, 1992). MICP analysis measures the pressures required to move mercury through the pore network system of a seal rock. The resulting data can be used to derive the height of a column of reservoir rock saturated by a particular fluid (e.g., CO_2) that the sealing strata would be capable of holding back (Gibson-Poole *et al.*, 2002).

4.1.3 Geomechanical factors affecting site integrity

When CO_2 is injected into a porous and permeable reservoir rock, it will be forced into pores at a pressure higher than that in the surrounding formation. This pressure could lead to deformation of the reservoir rock or the seal rock, resulting in the opening of fractures or failure along a fault plane. Geomechanical modelling of the subsurface is necessary in any storage site assessment and should focus on the maximum formation pressures that can be sustained in a storage site. As an example, at Weyburn, where the initial reservoir pressure is 14.2 MPa, the maximum injection pressure (90% of fracture pressure) is in the range of 25–27 MPa and fracture pressure is in the range of 29–31 MPa. Coupled geomechanical-geochemical modelling may also be needed to document fracture sealing by precipitation of carbonates in fractures or pores. Modelling these will require knowledge of pore fluid composition, mineralogy, *in situ* stresses, pore fluid pressures and pre-existing fault orientations and their frictional properties (Streit and Hillis, 2003; Johnson *et al.*, 2005). These estimates can be made from conventional well and seismic data and leak-off tests, but the results can be enhanced by access to physical measurements of rock strength. Application of this methodology at a regional scale is documented by Gibson-Poole *et al.* (2002).

The efficacy of an oil or gas field seal rock can be characterized by examining its capillary entry pressure and the potential hydrocarbon column height that it can sustain (see above). However, Jimenez and Chalaturnyk (2003) suggest that the geomechanical processes, during depletion and subsequent CO_2 injection, may affect the hydraulic integrity of the seal rock in hydrocarbon fields. Movement along faults can be produced in a hydrocarbon field by induced changes in the preproduction stress regime. This can happen when fluid pressures are substantially depleted during hydrocarbon production (Streit and Hillis, 2003). Determining whether the induced stress changes result in compaction or pore collapse is critical in assessment of a depleted field. If pore collapse occurs, then it might not be possible to return a pressure-depleted field to its original pore pressure without the risk of induced failure. By having a reduced maximum pore fluid pressure, the total volume of CO_2 that can be stored in a depleted field could be substantially less than otherwise estimated.

4.1.4 Geochemical factors affecting site integrity

The mixing of CO_2 and water in the pore system of the reservoir rock will create dissolved CO_2, carbonic acid and bicarbonate ions. The acidification of the pore water reduces the amount of CO_2 that can be dissolved. As a consequence, rocks that buffer the pore water increases *p*H to higher values (reducing the acidity) facilitate the storage of CO_2 as a dissolved phase (Section 3.2). The CO_2-rich water may react with minerals in the reservoir rock or caprock matrix or with the primary pore fluid. Importantly, it may also react with borehole cements and steels (see discussion below). Such reactions may cause either mineral dissolution or potential breakdown of the rock (or cement) matrix or mineral precipitation and plugging of the pore system (and thus, reduction in permeability).

A carbonate mineral formation effectively traps stored CO_2 as an immobile solid phase (Section 3.2). If the mineralogical composition of the rock matrix is strongly dominated by quartz, geochemical reactions will be dominated by simple dissolution into the brine and CO_2-water-rock reactions can be neglected. In this case, complex geochemical simulations of rock-water interactions will not be needed. However, for more complex mineralogies, sophisticated simulations, based on laboratory experimental data that use reservoir and caprock samples and native pore fluids, may be necessary to fully assess the potential effects of such reactions in more complex systems (Bachu *et al.*, 1994; Czernichowski-Lauriol *et al.*, 1996; Rochelle *et al.*, 1999, 2004; Gunter *et al.*, 2000). Studies of rock samples recovered from natural systems rich in CO_2 can provide indications of what reactions might occur in the very long term (Pearce *et al.*, 1996). Reactions in boreholes are considered by Crolet (1983), Rochelle *et al.* (2004) and Schremp and Roberson (1975). Natural CO_2 reservoirs also allow sampling of solid and fluid reactants and reaction products, thus allowing formulation of geochemical models that can be verified with numerical simulations, further facilitating quantitative predictions of water-CO_2-rock reactions (May, 1998).

4.1.5 Anthropogenic factors affecting storage integrity

As discussed at greater length in Section 6.2, anthropogenic factors such as active or abandoned wells, mine shafts and subsurface production can impact storage security. Abandoned wells that penetrate the storage formation can be of particular concern because they may provide short circuits for CO_2 to leak from the storage formation to the surface (Celia and Bachu, 2003; Gasda *et al.*, 2004). Therefore, locating and assessing the condition of abandoned and active wells is an important component of site characterization. It is possible to locate abandoned wells with airborne magnetometer surveys. In most cases, abandoned wells will have metal casings, but this may not be the case for wells drilled long ago or those never completed for oil or gas production. Countries with oil and gas production will have at least some records of the more recently drilled wells, depth of wells and other information stored in a geographic database. The consistency and quality of record keeping of drilled wells (oil and gas, mining exploration and water) varies considerably, from excellent for recent wells to nonexistent, particularly for older wells (Stenhouse *et al.*, 2004).

4.2 Performance prediction and optimization modelling

Computer simulation also has a key role in the design and operation of field projects for underground injection of CO_2. Predictions of the storage capacity of the site or the expected incremental recovery in enhanced recovery projects are vital to an initial assessment of economic feasibility. In a similar vein, simulation can be used in tandem with economic assessments to optimize the location, number, design and depth of injection wells. For enhanced recovery projects, the timing of CO_2 injection relative to production is vital to the success of the operation and the effect of various strategies can be assessed by simulation. Simulations of the long-term distribution of CO_2 in the subsurface (e.g., migration rate and direction and rate of dissolution in the formation water) are important for the design of cost-effective monitoring programmes, since the results will influence the location of monitoring wells and the frequency of repeat measurements, such as for seismic, soil gas or water chemistry. During injection and monitoring operations, simulation models can be adjusted to match field observations and then used to assess the impact of possible operational changes, such as drilling new wells or altering injection rates, often with the goal of further improving recovery (in the context of hydrocarbon extraction) or of avoiding migration of CO_2 past a likely spill-point.

Section 3.2 described the important physical, chemical and geomechanical processes that must be considered when evaluating a storage project. Numerical simulators currently in use in the oil, gas and geothermal energy industries provide important subsets of the required capabilities. They have served as convenient starting points for recent and ongoing development efforts specifically targeted at modelling the geological storage of CO_2. Many simulation codes have been used and adapted for this purpose (White, 1995; Nitao, 1996; White and Oostrom, 1997; Pruess *et al.*, 1999; Lichtner, 2001; Steefel, 2001; Xu *et al.*, 2003).

Simulation codes are available for multiphase flow processes, chemical reactions and geomechanical changes, but most codes account for only a subset of these processes. Capabilities for a comprehensive treatment of different processes are limited at present. This is especially true for the coupling of multiphase fluid flow, geochemical reactions and (particularly) geomechanics, which are very important for the integrity of potential geological storage sites (Rutqvist and Tsang, 2002). Demonstrating that they can model the important physical and chemical processes accurately and reliably is necessary for establishing credibility as practical engineering tools. Recently, an analytical model developed for predicting the evolution of a plume of CO_2 injected into a deep saline formation, as well as potential CO_2 leakage rates through abandoned wells, has shown good matching with results obtained from the industry numerical simulator ECLIPSE (Celia *et al.*, 2005; Nordbotten *et al.*, 2005b).

A code intercomparison study involving ten research groups from six countries was conducted recently to evaluate the capabilities and accuracy of numerical simulators for geological storage of greenhouse gases (Pruess *et al.*, 2004). The test problems addressed CO_2 storage in saline formations and oil and gas reservoirs. The results of the intercomparison were encouraging in that substantial agreement was found between results obtained with different simulators. However, there were also areas with only fair agreement, as well as some significant discrepancies. Most discrepancies could be traced to differences in fluid property descriptions, such as fluid densities and viscosities and mutual solubility of CO_2 and water. The study concluded that 'although code development work undoubtedly must continue . . . codes are available now that can model the complex phenomena accompanying geological storage of CO_2 in a robust manner and with quantitatively similar results' (Pruess *et al.*, 2004).

Code intercomparisons are useful for checking mathematical methods and numerical approximations and to provide insight into relevant phenomena by using the different descriptions of the physics (or chemistry) implemented. However, establishing the realism and accuracy of physical and chemical process models is a more demanding task, one that requires carefully controlled and monitored field and laboratory experiments. Only after simulation models have been shown to be capable of adequately representing real-world observations can they be relied upon for engineering design and analysis. Methods for calibrating models to complex engineered subsurface systems are available, but validating them requires field testing that is time consuming and expensive.

The principal difficulty is that the complex geological models on which the simulation models are based are subject to considerable uncertainties, resulting both from uncertainties in data interpretation and, in some cases, sparse data sets. Measurements taken at wells provide information on rock and fluid properties at that location, but statistical techniques must be used to estimate properties away from the wells. When simulating a field in which injection or production is already occurring, a standard approach in the oil and gas industry is to adjust some parameters of the geological model to match selected field observations. This does not prove that the model is correct, but it does provide additional constraints on the model parameters. In the case of saline formation storage, history matching is generally not feasible for constraining uncertainties, due to a lack of underground data for comparison. Systematic parameter variation routines and statistical functions should be included in future coupled simulators to allow uncertainty estimates for numerical reservoir simulation results. Field tests of CO_2 injection are under way or planned in several countries and these tests provide opportunities to validate simulation models.

Predictions of the long-term distribution of injected CO_2, including the effects of geochemical reactions, cannot be directly validated on a field scale because these reactions may take hundreds to thousands of years. However, the simulation of important mechanisms, such as the convective mixing of dissolved CO_2, can be tested by comparison to laboratory analogues (Ennis-King and Paterson, 2003). Another possible route is to match simulations to the geochemical changes that have occurred in appropriate natural underground accumulations of CO_2, such as the precipitation of carbonate minerals, since these provide evidence for the slow processes that affect the long-term distribution of CO_2 (Johnson *et al.*, 2005). It is also important to have reliable and accurate data regarding the thermophysical properties of CO_2 and mixtures of CO_2 with methane, water and potential contaminants such as H_2S and SO_2. Similarly, it is important to have data on relative permeability and capillary pressure under drainage and imbibition conditions. Code comparison studies show that the largest discrepancies between different simulators can be traced to uncertainties in these parameters (Pruess *et al.*, 2004). For sites where few, if any, CO_2-water-rock interactions occur, reactive chemical transport modelling may not be needed and simpler simulations that consider only CO_2-water reactions will suffice.

4.3 Remark

So far in this chapter, only the nature of the storage site is considered. But once a suitable site is identified, it is important to assess the technology available to inject large quantities of CO_2 (1–10 $MtCO_2\ yr^{-1}$) into the subsurface and to operate the site effectively and safely. A number of technological issues need to be examined. A list of the important issues with regard to technology and field operations is outlined below.

- Injection well technologies
- Well abandonment procedures
- Injection well pressure and reservoir constraints
- Field operations and surface facilities

Details on specific issues can be obtained from the IPCC, 2005 report and saline aquifer CO_2 storage Best Practice Manual (2004).

5 Monitoring and verification

5.1 Purposes for monitoring

Monitoring is needed for a wide variety of purposes. Specifically, monitoring can be used to:

- Ensure and document effective injection well controls, specifically for monitoring the condition of the injection well and measuring injection rates, wellhead and formation pressures. Petroleum industry experience suggests that leakage from the injection well itself, resulting from improper completion or deterioration of the casing, packers or cement, is one of the most significant potential failure modes for injection projects (Apps, 2005; Perry, 2005);
- Verify the quantity of injected CO_2 that has been stored by various mechanisms;
- Optimize the efficiency of the storage project, including utilization of the storage volume, injection pressures and drilling of new injection wells;
- Demonstrate with appropriate monitoring techniques that CO_2 remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO_2 remains stored and that performance predictions can be verified;
- Detect leakage and provide an early warning of any seepage or leakage that might require mitigating action.

In addition to essential elements of a monitoring strategy, other parameters can be used to optimize storage projects, deal with unintended leakage and address regulatory, legal and social issues. Other important purposes for monitoring include assessing the integrity of plugged or abandoned wells, calibrating and confirming performance assessment models (including 'history matching'), establishing baseline parameters for the storage site to ensure that CO_2-induced changes are recognized (Wilson and Monea, 2005), detecting microseismicity associated with a storage project, measuring surface fluxes of CO_2 and designing and monitoring remediation activities (Benson *et al.*, 2004).

Before monitoring of subsurface storage can take place effectively, a baseline survey must be taken. This survey provides the point of comparison for subsequent surveys. This is particularly true of seismic and other remote-sensing technologies, where the identification of saturation of fluids with CO_2 is based on comparative analysis. Baseline monitoring is also a prerequisite for geochemical monitoring, where anomalies are identified relative to background concentrations. Additionally, establishing a baseline of CO_2 fluxes resulting from ecosystem cycling of CO_2, both on diurnal and annual cycles, are useful for distinguishing natural fluxes from potential storage-related releases.

Much of the monitoring technology described below was developed for application in the oil and gas industry. Most of these techniques can be applied to monitoring storage projects in all types of geological formations, although much remains to be learned about monitoring coal formations. Monitoring experience from natural gas storage in saline aquifers can also provide a useful industrial analogue.

5.2 Monitoring

5.2.1 Injection rates and pressures

To ensure that injection of CO_2 is properly taking place at a site, monitoring of the condition of the injection well is necessary. Measurements of CO_2 injection rates are a common oil field practice and instruments for this purpose are available commercially. Measurements are made by gauges either at the injection wellhead or near distribution manifolds. Typical systems use orifice meters or other devices that relate the pressure drop across the device to the flow rate. Modern systems have improved accuracies in the order of 0.6% compared to conventional systems with 8% measurement accuracy. Standards for measurement accuracy vary and are usually established by governments or industrial associations. For example, in the United States, current auditing practices for CO_2-EOR accept flow meter precision of ±4%.

Measurements of injection pressure at the surface and in the formation are also routine processes. Pressure gauges are installed on most injection wells through orifices in the surface piping near the wellhead. Downhole pressure measurements are routine, but are used for injection well testing or under special circumstances in which surface measurements do not provide reliable information about the downhole pressure. A wide variety of pressure sensors are available and suitable for monitoring pressures at the wellhead or in the formation. These instruments are used to monitor injection pressures through shut-off valves that will stop or curtail injection if the pressure exceeds a predetermined safe threshold or if there is a drop in pressure as a result of a leak. Surface pressures can be used to ensure that downhole pressures do not exceed the threshold of reservoir fracture pressure. Modern systems such as fibre-optic pressure and temperature sensors are expected to provide more reliable measurements and well control.

5.2.2 Subsurface distribution of CO_2

Several techniques are used to monitor the distribution and migration of CO_2 in the subsurface (e.g. Best Practice Manual, 2004). The applicability and sensitivity of the techniques are somewhat site-specific. The techniques available for monitoring CO_2 migration are classified in to:

- Direct techniques, and
- Indirect techniques

Direct techniques employ direct measurement of injected CO_2 for example at production wells for monitoring the arrival of CO_2 and are limited in availability at present. In the case of Weyburn, the carbon in the injected CO_2 has a different isotopic composition from the carbon in the reservoir (Emberley *et al.*, 2002), so the distribution of the CO_2 can be determined on a gross basis by evaluating the arrival of the introduced CO_2 at different production wells. With multiple injection wells in any producing area, the arrival of CO_2 can give only a general indication of distribution in the reservoir.

A more accurate approach is to use tracers (gases or gas isotopes not present in the reservoir system) injected into specific wells. The timing of the arrival of the tracers at production or monitoring wells will indicate the path the CO_2 is taking through the reservoir. Monitoring wells may also be used to passively record the movement of CO_2 past the well, although it should be noted that the use of such invasive techniques potentially creates new pathways for leakage to the surface. This provides some indication of the lateral distribution of the CO_2 in a storage reservoir. In thick formations, multiple sampling along vertical monitoring or production wells would provide some indication of the vertical distribution of the CO_2 in the formation.

Direct measurement of migration beyond the storage site can be achieved in a number of ways, depending on where the migration takes the CO_2. Comparison between baseline surveys of water quality and/or isotopic composition can be used to identify new CO_2 arrival at a specific location from natural CO_2 pre-existing at that site. Geochemical techniques can also be used to understand more about the CO_2 and its movement through the reservoir (Czernichowski-Lauriol *et al.*, 1996; Wilson and Monea, 2005). The chemical changes that occur in the reservoir fluids indicate the increase in acidity and the chemical effects of this change, in particular the bicarbonate ion levels in the fluids. At the surface, direct measurement can be undertaken by sampling for CO_2 or tracers in soil gas and near surface water-bearing horizons (from existing water wells or new observation wells). Surface CO_2 fluxes may be directly measurable by techniques such as infrared spectroscopy (Miles *et al.*, 2005; Pickles, 2005; Shuler and Tang, 2005).

Indirect techniques for measuring CO_2 distribution in the subsurface include a variety of seismic and non-seismic geophysical and geochemical techniques (Benson *et al.*, 2004; Arts and Winthaegen, 2005; Hoversten and Gasperikova, 2005). Seismic techniques basically measure the velocity and energy absorption of waves, generated artificially or naturally, through rocks. The transmission is modified by the nature of the rock and its contained fluids. By taking a series of surveys over time, it is possible to trace the distribution of the CO_2 in the reservoir, assuming the free-phase CO_2 volume at the site is sufficiently high to identify from the processed data. A baseline survey with no CO_2 present provides the basis against which comparisons can be made. It would appear that relatively low volumes of free-phase CO_2 (approximately 5% or more) may be identified by these seismic techniques; at present, attempts are being made to quantify the amount of CO_2 in the pore space of the rocks and the distribution within the reservoir (Hoversten *et al.*, 2003).

The use of passive seismic (microseismic) techniques also has potential value. Passive seismic monitoring detects microseismic events induced in the reservoir by dynamic responses to the modification of pore pressures or the reactivation or creation of small fractures. These discrete microearthquakes, with magnitudes on the order of -4 to 0 on the Richter scale (Wilson and Monea, 2005), are picked up by static arrays of sensors, often cemented into abandoned wells. These microseismic events are extremely small, but monitoring the microseismic events may allow the tracking of pressure changes and, possibly, the movement of gas in the reservoir or saline formation.

Non-seismic geophysical techniques include the use of electrical and electromagnetic and self-potential techniques (Benson *et al.*, 2004; Hoversten and Gasperikova, 2005). In addition, though not proven gravity techniques (ground or air-based) may be used to determine the migration of the CO_2 plume in the subsurface. Finally, tiltmeters or remote methods (geospatial surveys from aircraft or satellites) for measuring ground distortion may be used in some environments to assess subsurface movement of the plume.

5.2.3 *Injection well integrity*

A number of standard technologies are available for monitoring the integrity of active injection wells. Cement bond logs are used to assess the bond and the continuity of the cement around well casing. Periodic cement bond logs can help detect deterioration in the cemented portion of the well and may also indicate any chemical interaction of the acidized formation fluids with the cement. The initial use of cement bond logs as part of the well integrity testing can indicate problems with bonding and even the absence of cement.

Prior to converting a well to other uses, such as CO_2 injection, the well usually undergoes testing to ensure its integrity under pressure. These tests are relatively straightforward, with the well being sealed top and bottom (or in the zone to be tested), pressured up and its ability to hold pressure measured. In general, particularly on land, the well will be abandoned if it fails the test and a new well will be drilled, as opposed to attempting any remediation on the defective well.

Injection takes place through a pipe that is lowered into the well and packed off above the perforations or open-hole portion of the well to ensure that the injectant reaches the appropriate level. The pressure in the annulus, the space between the casing and the injection pipe, can be monitored to ensure the integrity of the packer, casing and the injection pipe. Changes in pressure or gas composition in the annulus will alert the operator to problems.

As noted above, the injection pressure is carefully monitored to ensure that there are no problems. A rapid increase in pressure could indicate problems with the well, although industry interpretations suggest that it is more likely to be loss of injectivity in the reservoir.

Temperature logs and 'noise' logs are also often run on a routine basis to detect well failures in natural gas storage projects. Rapid changes in temperature along the length of the wellbore are diagnostic of casing leaks. Similarly, 'noise' associated with leaks in the injection tubing can be used to locate small leaks (Lippmann and Benson, 2003).

5.2.4 *Local environmental effects*

Monitoring local environmental effects are important in the events that CO_2 leaks from deep geological storage formation and migrates upwards. Monitoring can be performed by assessing:

- Groundwater quality
- Air quality and atmospheric fluxes,
- Ecosystems

Groundwater - If CO_2 leaks from the deep geological storage formation and migrates upwards into overlying shallow groundwater aquifers, methods are available to detect and assess changes in groundwater quality. Seismic monitoring methods and potentially others (described as indirect techniques), can be used to identify leaks before the CO_2 reaches the groundwater zone.

Nevertheless, if CO_2 does migrate into a groundwater aquifer, potential impacts can be assessed by collecting groundwater samples and analyzing them for major ions (e.g., Na, K, Ca, Mg, Mn, Cl, Si, HCO_3^- and SO_4^{2-}), *p*H, alkalinity, stable isotopes (e.g., ^{13}C, ^{14}C, ^{18}O, ^{2}H)

and gases, including hydrocarbon gases, CO_2 and its associated isotopes (Gunter *et al.*, 1998). Additionally, if shallow groundwater contamination occurs, samples could be analyzed for trace elements such as arsenic and lead, which are mobilized by acidic water. Several modern techniques are used to accurately measure water quality. Standard analytical methods are available to monitor all of these parameters, including the possibility of continuous real-time monitoring for some of the geochemical parameters.

Natural tracers (isotopes of C, O, H and noble gases associated with the injected CO_2) and introduced tracers (noble gases, SF_6 and perfluorocarbons) also may provide insight into the impacts of storage projects on groundwater (Emberley *et al.*, 2002; Nimz and Hudson, 2005). (SF_6 and perfluorocarbons are greenhouse gases with extremely high global warming potentials and therefore caution is warranted in the use of these gases, to avoid their release to the atmosphere.) Natural tracers such as C and O isotopes may be able to link changes in groundwater quality directly to the stored CO_2 by 'fingerprinting' the CO_2, thus distinguishing storage-induced changes from changes in groundwater quality caused by other factors. Introduced tracers such as perfluorocarbons that can be detected at very low concentrations (1 part per trillion) may also be useful for determining whether CO_2 has leaked and is responsible for changes in groundwater quality. Synthetic tracers could be added periodically to determine movement in the reservoir or leakage paths, while natural tracers are present in the reservoir or introduced gases.

Air quality and atmospheric fluxes - Continuous sensors for monitoring CO_2 in air are used in a variety of applications, including HVAC (heating, ventilation and air conditioning) systems, greenhouses, combustion emissions measurement and environments in which CO_2 is a significant hazard (such as breweries). Such devices rely on infrared detection principles and are referred to as infrared gas analyzers. For extra assurance and validation of real-time monitoring data, periodic concentration measurement by gas chromatography is in common use. Mass spectrometry is the most accurate method for measuring CO_2 concentration, but it is also the least portable. Electrochemical solid state CO_2 detectors exist, but they are not cost effective at this time (e.g., Tamura *et al.*, 2001). Common field applications in environmental science include the measurement of CO_2 concentrations in soil air, flux from soils and ecosystem-scale carbon dynamics. Diffuse soil flux measurements are made by simple infrared analyzers (Oskarsson *et al.*, 1999).

Satellite-based remote sensing of CO_2 releases to the atmosphere may also be possible, but this method remains challenging because of the long path length through the atmosphere over which CO_2 is measured and the inherent variability of atmospheric CO_2. Infrared detectors measure average CO_2 concentration over a given path length. Aeroplane-based measurement using this same principle may be possible. Carbon dioxide has been measured either directly in the plume by a separate infrared detector or calculated from SO_2 measurements and direct ground sampling of the SO_2: CO_2 ratio for a given volcano or event (Hobbs *et al.*, 1991; USGS, 2001b). Remote-sensing techniques currently under investigation for CO_2 detection are LIDAR (light detection and range-finding), a scanning airborne laser and DIAL (differential absorption LIDAR), which looks at reflections from multiple lasers at different frequencies (Hobbs *et al.*, 1991; Menzies *et al.*, 2001).

In summary, monitoring of CO_2 for occupational safety is well established. On the other hand, while some promising technologies are under development for environmental monitoring and leak detection, measurement and monitoring approaches on the temporal and space scales relevant to geological storage need improvement to be truly effective.

Ecosystems - The health of terrestrial and subsurface ecosystems can be determined directly by measuring the productivity and biodiversity of flora and fauna and in some cases (such as at Mammoth Mountain in California) indirectly by using remote sensing techniques such as hyperspectral imaging (Martini and Silver, 2002; Onstott, 2005; Pickles, 2005). In many areas with natural CO_2 seeps, even those with very low CO_2 fluxes, the seeps are generally quite conspicuous features. They are easily recognized in populated areas, both in agriculture and natural vegetation, by reduced plant growth and the presence of precipitants of minerals leached from rocks by acidic water. Therefore, any conspicuous site could be quickly and easily checked for excess CO_2 concentrations without any large remote-sensing ecosystem studies or surveys. However, in desert environments where vegetation is sparse, direct observation may not be possible. In addition to direct ecosystem observations, analyses of soil gas composition and soil mineralogy can be used to indicate the presence of CO_2 and its impact on soil properties. Detection of elevated concentrations of CO_2 or evidence of excessive soil weathering would indicate the potential for ecosystem impacts.

For aquatic ecosystems, water quality and in particular low *p*H, would provide a diagnostic for potential impacts. Direct measurements of ecosystem productivity and biodiversity can also be obtained by using standard techniques developed for lakes and marine ecosystems. There are a variety of strategies for monitoring release of CO_2 into the ocean from fixed locations. Brewer *et al.* (2005) observed a plume of CO_2-rich sea water emanating from a small scale experimental release at 4 km depth with an array of *p*H and conductivity sensors. Measurements of ocean *p*H and current profiles at sufficiently high temporal resolution could be used to evaluate the rate of CO_2 release, local CO_2 accumulation and net transport away from the site (Sundfjord *et al.*, 2001). Undersea video cameras can monitor the point of release to observe CO_2 flow. The very large sound velocity contrast between liquid CO_2 (about 300 m s^{-1}) and sea water (about 1,500 m s^{-1}) offers the potential for very efficient monitoring of the liquid CO_2 phase using acoustic techniques (e.g., sonar).

5.2.5 ***Network design and duration***

There are currently no standard protocols or established network designs for monitoring leakage of CO_2. Monitoring network design will depend on the objectives and requirements of the monitoring programme, which will be determined by regulatory requirements and perceived risks posed by the site (Chalaturnyk and Gunter, 2005). For example, the monitoring designed for the Weyburn Project uses seismic surveys to determine the lateral migration of CO_2 over time. This is compared with the simulations undertaken to design the operational practices of the CO_2 flood. For health and safety, the programme is designed to test groundwater for contamination and to monitor for gas build-up in working areas of the field to ensure worker safety. The surface procedure also uses pressure monitoring to ensure that the fracture pressure of the formation is not exceeded (Chalaturnyk and Gunter, 2005).

The Weyburn Project is designed to assess the integrity of an oil reservoir for long-term storage of CO_2 (Wilson and Monea, 2005). In this regard, the demonstrated ability of seismic surveys to measure migration of CO_2 within the formation is important, but in the long term it may be more important to detect CO_2 that has leaked out of the storage reservoir. In this case, the monitoring programme should be designed to achieve the resolution and sensitivity needed to detect CO_2 that has leaked out of the reservoir and is migrating vertically. Chalaturnyk and Gunter (2005) suggest that an effectively designed monitoring programme should allow decisions to be made in the future that are based on ongoing interpretation of the data. The data from the programme should also provide the information necessary to decrease uncertainties over time or increase monitoring demand if things develop unexpectedly. The corollary to this is that unexpected changes may result in the requirement of increased monitoring until new uncertainties are resolved.

The purpose of long-term monitoring is to identify movement of CO_2 that may lead to releases that could impact long-term storage security and safety, as well as trigger the need for remedial action. Long-term monitoring can be accomplished with the same suite of monitoring technologies used during the injection phase. However, at the present time, there are no established protocols for the kind of monitoring that will be required, by whom, for how long and with what purpose. Geological storage of CO_2 may persist over many millions of years. The long duration of storage raises some questions about long-term monitoring. Several studies have attempted to address these issues. Keith and Wilson (2002) have proposed that governments assume responsibility for monitoring after the active phase of the storage project is over, as long as all regulatory requirements have been met during operation. This study did not, however, specify long-term requirements for monitoring. Though perhaps somewhat impractical in terms of implementation, White *et al.* (2003) suggested that monitoring might be required for thousands of years. An alternative point of view is presented by Chow *et al.* (2003) and Benson *et al.* (2004), who suggest that once it has been demonstrated that the plume of CO_2 is no longer moving, further monitoring should not be required. The rationale for this point of view is that long-term monitoring provides little value if the plume is no longer migrating or the cessation of migration can be accurately predicted and verified by a combination of modelling and short- to mid-term monitoring.

Until long-term monitoring requirements are established (Stenhouse *et al.*, 2005) it is not possible to evaluate which technology or combination of technologies for monitoring will be needed or desired. However, today's technology could be deployed to continue monitoring the location of the CO_2 plume over very long time periods with sufficient accuracy to assess the risk of the plume intersecting potential pathways, natural or human, out of the storage site into overlying zones. If CO_2 escapes from the primary storage reservoir with no prospect of remedial action to prevent leakage, technologies are available to monitor the consequent environmental impact on groundwater, soils, ecosystems and the atmosphere.

5.3 Verification of CO_2 injection and storage inventory

Overlap exists in usage between the terms 'verification' and 'monitoring'. For this report, 'verification' is defined as the set of activities used for assessing the amount of CO_2 that is stored underground and for assessing how much, if any, is leaking back into the atmosphere. Complete standard protocols have not been fully developed specifically for verification of geological storage. However, experience at the Weyburn and Sleipner projects has demonstrated the utility of various techniques for most if not all aspects of verification (Wilson and Monea, 2005; Best Practice Manual, 2004). At the very least, verification will require measurement of the quantity of CO_2 stored. Demonstrating that it remains within the storage site, from both a lateral and vertical migration perspective, is likely to require some combination of models and monitoring. Requirements may be site-specific, depending on the regulatory environment, requirements for economic instruments and the degree of risk of leakage. The oversight for verification may be handled by regulators, either directly or by independent third parties contracted by regulators under national law.

6 Risk assessment, management, and remediation

6.1 Frameworks for assessing environmental risks

The environmental impacts arising from geological storage fall into two broad categories:

- Local environmental effects and
- Global effects arising from the release of stored CO_2 to the atmosphere

Global effects of CO_2 storage may be viewed as the uncertainty in the effectiveness of CO_2 storage. Local health, safety and environmental hazards arise from three distinct causes:

- Direct effects of elevated gas-phase CO_2 concentrations in the shallow subsurface and near-surface environment;
- Effects of dissolved CO_2 on groundwater chemistry;
- Effects that arise from the displacement of fluids by the injected CO_2.

Risks are proportional to the magnitude of the potential hazards and the probability that these hazards will occur. For hazards that arise from locally elevated CO_2 concentrations – in the near-surface atmosphere, soil gas or in aqueous solution – the risks depend on the probability of leakage from the deep storage site to the surface. Regarding those risks associated with routine operation of the facility and well maintenance, such risks are expected to be comparable to CO_2-EOR operations.

There are two important exceptions to the rule that risk is proportional to the probability of release. First, local impacts will be strongly dependent on the spatial and temporal distribution of fluxes and the resulting CO_2 concentrations. Episodic and localized seepage will likely tend to have more significant impacts per unit of CO_2 released than will seepage that is continuous and or spatially dispersed. Global impacts arising from release of CO_2 to the atmosphere depend only on the average quantity released over time scales of decades to centuries. Second, the hazards arising from displacement, such as the risk of induced seismicity, are roughly independent of the probability of release.

Although there are limited experience with injection of CO_2 for the explicit purpose of avoiding atmospheric emissions, a wealth of closely related industrial experience and scientific knowledge exists that can serve as a basis for appropriate risk management.

6.2 Processes and pathways for release of CO_2 from geological storage sites

Carbon dioxide that exists as a separate phase (supercritical, liquid or gas) may escape from formations used for geological storage through the following pathways (Figure 15):

- Through the pore system in low-permeability caprocks such as shales, if the capillary entry pressure at which CO_2 may enter the caprock is exceeded;
- Laterally along unconformities or along porous rocks that end up at sea bottom
- Through openings in the caprock or fractures and faults;
- Through anthropomorphic pathways, such as poorly completed and/or abandoned pre-existing wells.

For storage sites that are offshore, CO_2 that has leaked may reach the ocean bottom sediments and then, if lighter than the surrounding water, migrate up through the water column until it reaches the atmosphere. Depending upon the leakage rate, it may either remain as a separate phase or completely dissolve into the water column. When CO_2 dissolves, biological impacts to ocean bottom and marine organisms will be of concern. For those sites where separate-phase CO_2 reaches the ocean surface, hazards to offshore platform workers may be of concern for very large and sudden release rates.

Once through the vadose zone, escaping CO_2 reaches the surface layer of the atmosphere and the surface environment, where humans and other animals can be exposed to it and could be hazardous. Therefore, this must be carefully considered in any risk assessment of a CO_2 storage site. Additionally, high subsurface CO_2 concentrations may accumulate in basements, subsurface vaults and other subsurface infrastructures where humans may be exposed to risk.

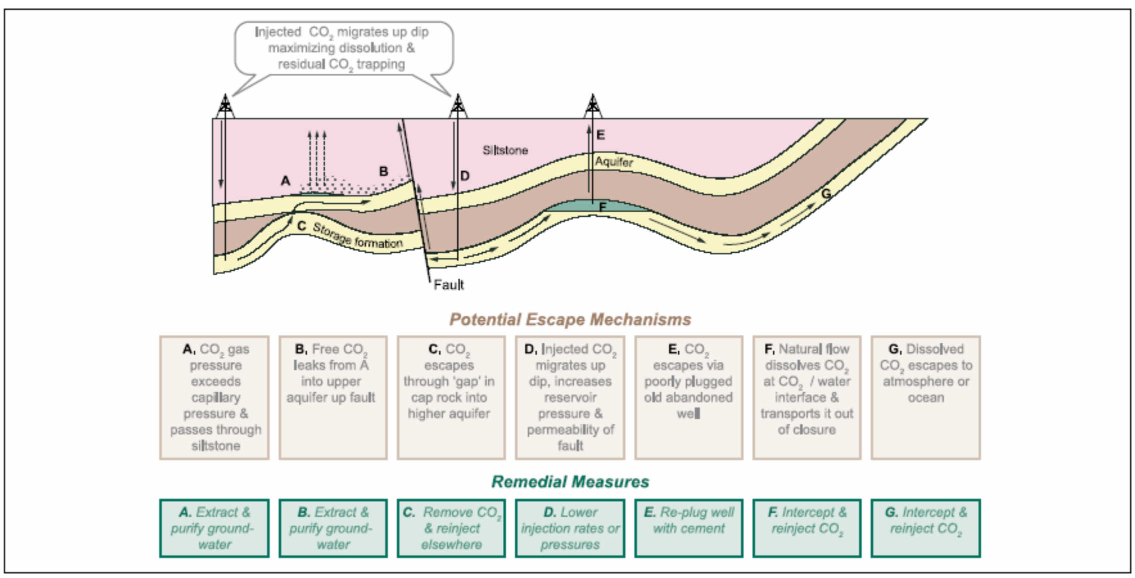

Figure 15 Some potential escape routes for CO_2 injected into saline formations (IPCC, 2005).

Injection wells and abandoned wells have been identified as one of the most probable leakage pathways for CO_2 storage projects (Gasda *et al.*, 2004; Benson, 2005). When a well is drilled, a continuous, open conduit is created between the land surface and the deep subsurface. If, at the time of drilling, the operator decides that the target formation does not look sufficiently productive, then the well is abandoned as a 'dry hole', in accordance with proper regulatory guidelines.

Drilling and completion of a well involve not only creation of a hole in the Earth, but also the introduction of engineered materials into the subsurface, such as well cements and well casing. The overall effect of well drilling is replacement of small but potentially significant cylindrical volumes of rock, including low-permeability caprock, with anthropomorphic materials that have properties different from those of the original materials. A number of possible leakage pathways can occur along abandoned wells, as illustrated in Figure 16 (Gasda *et al.*, 2004).

These include leakage between the cement and the outside of the casing (Figure 16a), between the cement and the inside of the metal casing (Figure 16b), within the cement plug itself (Figure 16c), through deterioration (corrosion) of the metal casing (Figure 16d), deterioration of the cement in the annulus (Figure 16e) and leakage in the annular region between the formation and the cement (Figure 16f). The potential for long-term degradation of cement and metal casing in the presence of CO_2 is a topic of extensive investigations at this time (e.g., Scherer *et al.*, 2005).

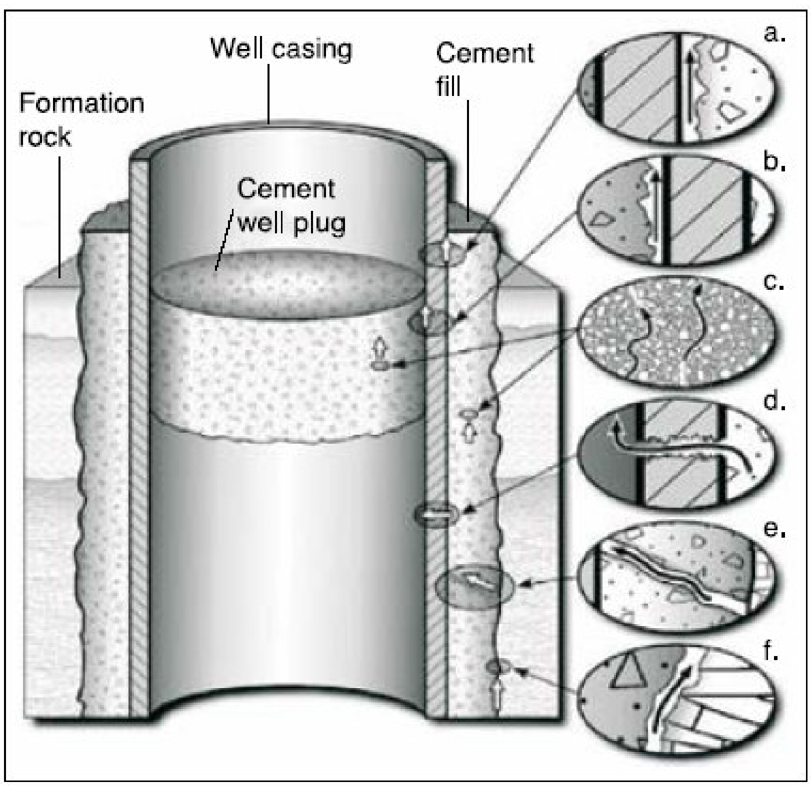

Figure 16 Possible leakage pathways in an abandoned well: (a) and (b) between casing and cement wall and plug, respectively; (c) through cement plugs; (d) through casing; (e) through cement wall; and (f) between the cement wall and rock (after Gasda *et al.*, 2004).

The risk of leakage through abandoned wells is proportional to the number of wells intersected by the CO_2 plume, their depth and the abandonment method used. For mature sedimentary basins, the number of wells in proximity to a possible injection well can be large, on the order of many hundreds. For example, in the Alberta Basin in western Canada, more than 350,000 wells have been drilled. Currently, drilling continues at the rate of approximately 20,000 wells per year. The wells are distributed spatially in clusters, with densities that average around four wells per km^2 (Gasda *et al.*, 2004). These data provides that storage security in mature oil and gas provinces may be compromised if a large number of wells penetrate the caprocks. Steps need to be taken to address this potential risk.

6.3 Risk assessment methodology

Risk assessment aims to identify and quantify potential risks caused by the subsurface injection of CO_2, where risk denotes a combination (often the product) of the probability of an event happening and the consequences of the event. Risk assessment should be an integral element of risk-management activities, spanning site selection, site characterization, storage system design, monitoring and, if necessary, remediation. The operation of a CO_2 storage facility will necessarily involve risks arising from the operation of surface facilities such as pipelines, compressors and wellheads. The assessment of such risks is routine practice in the oil and gas industry and available assessment methods like hazard and operability and quantitative risk assessment are directly applicable. Assessment of such risks can be made with considerable confidence, because estimates of failure probabilities and the consequences of failure can be based directly on experience. Techniques used for assessment of operational risks will not, in general, be readily applicable to assessment of risks arising from long-term storage of CO_2 underground. However, they are applicable to the operating phase of a storage project. The remainder of this subsection addresses the long-term risks.

Risk assessment methodologies are diverse; new methodologies arise in response to new classes of problems. Because analysis of the risks posed by geological storage of CO_2 is a new field, no well-established methodology for assessing such risks exists. Methods dealing with the long-term risks posed by the transport of materials through the subsurface have been developed in the area of hazardous and nuclear waste management (Hodgkinson and Sumerling, 1990; North, 1999). These techniques provide a useful basis for assessing the risks of CO_2 storage. Their applicability may be limited, however, because the focus of these techniques has been on assessing the low-volume disposal of hazardous materials, whereas the geological storage of CO_2 is high-volume disposal of a material that involves comparatively mild hazards.

Several substantial efforts are under way to assess the risks posed by particular storage sites (Gale, 2003). These risk assessment activities cover a wide range of reservoirs, use a diversity of methods and consider a very wide class of risks. The description of a representative selection of these risk assessment efforts is summarized in Table 3.

Table 3 Representative selection of risk assessment models and efforts (IPCC, 2005).

Project title	**Description and status**
Weyburn/ECOMatters	New model, CQUESTRA, developed to enable probabilistic risk assessment. A simple box model is used with explicit representation of transport between boxes caused by failure of wells.
Weyburn/Monitor Scientific	Scenario-based modelling that uses an industry standard reservoir simulation tool (Eclipse3000) based on a realistic model of known reservoir conditions. Initial treatment of wells involves assigning a uniform permeability.
NGCAS/ECL technology	Probabilistic risk assessment using fault tree and FEP (features, events and processes) database. Initial study focused on the Forties oil and gas field located offshore in the North Sea. Concluded that flow through caprock transport by advection in formation waters not important, work on assessing leakage due to well failures ongoing.
SAMARCADS (safety aspects of CO2 storage)	Methods and tools for HSE risk assessment applied to two storage systems an onshore gas storage facility and an offshore formation.
RITE	Scenario-based analysis of leakage risks in a large offshore formation. Will assess scenarios involving rapid release through faults activated by seismic events.
Battelle	Probabilistic risk assessment of an onshore formation storage site that is intended to represent the Mountaineer site.
GEODISC	Completed a quantitative risk assessment for four sites in Australia: the Petrel Sub-basin; the Dongra depleted oil and gas field; the offshore Gippsland Basin; and, offshore Barrow Island. Also produced a risk assessment report that addressed the socio-political needs of stakeholders.
UK-DTI	Probabilistic risk assessment of failures in surface facilities that uses models and operational data. Assessment of risk of release from geological storage that uses an expert-based Delphi process.

The development of a comprehensive catalogue of the risks and of the mechanisms that underlie them provides a good foundation for systematic risk assessment. Many of the ongoing risk assessment efforts are now cooperating to identify, classify and screen all factors that may influence the safety of storage facilities, by using the features, events and processes (FEP) methodology. In this context, *features* include a list of parameters, such as storage reservoir permeability, caprock thickness and number of injection wells. *Events* include processes such as seismic events, well blow-outs and penetration of the storage site by new wells. *Processes* refer to the physical and chemical processes, such as multiphase flow, chemical reactions and geomechanical stress changes that influence storage capacity and security. FEP databases tie information on individual FEPs to relevant literature and allow classification with respect to likelihood, spatial scale, and time scale and so on. However, there are alternative approaches.

Most risk assessments involve the use of scenarios that describe possible future states of the storage facility and events that result in leakage of CO_2 or other risks. Each scenario may be considered as an assemblage of selected FEPs. Some risk assessments define a reference scenario that represents the most probable evolution of the system. Variant scenarios are then constructed with alternative FEPs. Various methods are used to structure and rationalize the process of scenario definition in an attempt to reduce the role of subjective judgements in determining the outcomes.

Scenarios are the starting points for selecting and developing mathematical-physical models (Section 4.2). Such performance assessment models may include representations of all relevant components including the stored CO_2, the reservoir, the seal, the overburden, the soil and the atmosphere. Many of the fluid transport models used for risk assessment are derived from (or identical to) well-established models used in the oil and gas or groundwater management industries (Section 4.2). The detail or resolution of various components may vary greatly. Some models are designed to allow explicit treatment of uncertainty in input parameters (Saripalli *et al.*, 2003; Stenhouse *et al.*, 2005; Wildenborg *et al.*, 2005a).

Our understanding of abandoned-well behaviour over long time scales is at present relatively poor. Several groups are now collecting data on the performance of well construction materials in high-CO_2 environments and building wellbore simulation models that will couple geomechanics, geochemistry and fluid transport (Scherer *et al.*, 2005; Wilson and Monea, 2005). The combination of better models and new data should enable the integration of physically based predictive models of wellbore performance into larger performance-assessment models, enabling more systematic assessment of leakage from wells.

The parameter values (e.g., permeability of a caprock) and the structure of the performance assessment models (e.g., the processes included or excluded) will both be, in general, uncertain. Risk analysis may or may not treat this uncertainty explicitly. When risks are assessed deterministically, fixed parameter values are chosen to represent the (often unknown) probability distributions. Often the parameter values are selected 'conservatively'; that is, they are selected so that risks are overestimated, although in practice such selections are problematic because the relationship between the parameter value and the risk may itself be uncertain.

Wherever possible, it is preferable to treat uncertainty explicitly. In probabilistic risk assessments, explicit probability distributions are used for some (or all) parameters. Methods such as Monte Carlo analysis are then used to produce probability distributions for various risks. The required probability distributions may be derived directly from data or may involve formal quantification of expert judgements (Morgan and Henrion, 1999). In some cases, probabilistic risk assessment may require that the models be simplified because of limitations on available computing resources.

Studies of natural and engineered analogues provide a strong basis for understanding and quantifying the health, safety and environmental risks that arise from CO_2 that seeps from the shallow subsurface to the atmosphere. Natural analogues are of less utility in assessing the likelihood of various processes that transport CO_2 from the storage reservoir to the near-surface environment. This is because the geological character of such analogues (e.g., CO_2 transport and seepage in highly fractured zones shaped by volcanism) will typically be very different from sites chosen for geological storage. Engineered analogues such as natural gas storage and CO_2-EOR can provide a basis for deriving quantitative probabilistic models of well performance.

Results from actual risk and assessment for CO_2 storage are provided in 6.4.

6.4 Probability of release from geological storage sites

Storage sites will presumably be designed to confine all injected CO_2 for geological time scales. Nevertheless, experience with engineered systems suggests a small fraction of operational storage sites may release CO_2 to the atmosphere. No existing studies systematically estimate the probability and magnitude of release across a sample of credible geological storage systems. In the absence of such studies, this section synthesizes the lines of evidence that enable rough quantitative estimates of achievable fractions retained in storage. Five kinds of evidence are relevant to assessing storage effectiveness:

- Data from natural systems, including trapped accumulations of natural gas and CO_2, as well as oil;
- Data from engineered systems, including natural gas storage, gas re-injection for pressure support, CO_2 or miscible hydrocarbon EOR, disposal of acid gases and disposal of other fluids;
- Fundamental physical, chemical and mechanical processes regarding the fate and transport of CO_2 in the subsurface;
- Results from numerical models of CO_2 transport;
- Results from current geological storage projects.

6.4.1 Natural systems

Natural systems allow inferences about the quality and quantity of geological formations that could be used to store CO_2. The widespread presence of oil, gas and CO_2 trapped in formations for many millions of years implies that within sedimentary basins, impermeable formations (caprocks) of sufficient quality to confine CO_2 for geological time periods are present. For example, the about 200 Mt CO_2 trapped in the Pisgah Anticline, northeast of the Jackson Dome (Mississippi), is thought to have been generated in Late Cretaceous times, more than 65 million years ago (Studlick *et al.*, 1990). Retention times longer than 10 million years are found in many of the world's petroleum basins (Bradshaw *et al.*, 2005). Therefore evidence from natural systems demonstrates that reservoir seals exist that are able to confine CO_2 for millions of years and longer.

6.4.2 Engineered systems

Evidence from natural gas storage systems enables performance assessments of engineered barriers (wells and associated management and remediation) and of the performance of natural systems that have been altered by pressure cycling (Lippmann and Benson, 2003; Perry, 2005). Approximately 470 natural gas storage facilities are currently operating in the United States with a total storage capacity exceeding 160 Mt natural gas. There have been nine documented incidents of significant leakage: five were related to wellbore integrity, each of which was resolved by reworking the wells; three arose from leaks in caprocks, two of which were remediated and one of which led to project abandonment. The final incident involved early project abandonment owing to poor site selection (Perry, 2005). There are no estimates of the total volumes of gas lost resulting from leakage across all the projects. In one recent serious example of leakage, involving wellbore failure at a facility in Kansas, the total mass released was about 3000 t (Lee, 2001), equal to less than 0.002% of the total gas in storage in the United States and Canada. The capacity-weighted median age of the approximately 470 facilities exceeds 25 years. Given that the Kansas failure was among the worst in the cumulative operating history of gas storage facilities, the average annual release rates, expressed as a fraction of stored gas released per year, are likely below 10^{-5}. While such estimates of the expected (or statistical average) release rates are a useful measure of storage effectiveness, they should not be interpreted as implying that release will be a continuous process. The performance of natural gas storage systems may be regarded as a lower bound on that of CO_2 storage. One reason for this is that natural gas systems are designed for (and subject to) rapid pressure cycling that increases the probability of caprock leakage. On the other hand, CO_2 will dissolve in pore waters (if present), thereby reducing the risk of leakage. Perhaps the only respect in which gas storage systems present lower risks is that CH_4 is less corrosive than CO_2 to metallic components, such as well casings. Risks are higher in the case of leakage from natural gas storage sites because of the flammable nature of the gas.

6.4.3 *Fate of CO_2 in the subsurface*

As described in Section 3.2, scientific understanding of CO_2 storage and in particular performance of storage systems rests on a large body of knowledge in hydrogeology, petroleum geology, reservoir engineering and related geosciences. Current evaluation has identified a number of processes that alone or in combination can result in very long-term storage. Specifically, the combination of structural and stratigraphic trapping of separate-phase CO_2 below low-permeability caprocks, residual CO_2 trapping, solubility trapping and mineral trapping can create secure storage over geological time scales.

6.4.4 *Numerical simulations of long-term storage performance*

Simulations of CO_2 confinement in large-scale storage projects suggest that, neglecting abandoned wells, the movement of CO_2 through the subsurface will be slow. For example, Cawley *et al.* (2005) studied the effect of uncertainties in parameters such as the flow velocity in the aquifer and capillary entry pressure into caprock in their examination of CO_2 storage in the Forties Oilfield in the North Sea. Over the 1000 year time scale examined in their study, Cawley *et al.* (2005) found that less than 0.2% of the stored CO_2 enters into the overlying layers and even in the worse case, the maximum vertical distance moved by any of the CO_2 was less than halfway to the seabed. Similarly, Lindeberg and Bergmo (2003) studied the Sleipner field and found that CO_2 would not begin to escape due to molecular diffusion into the North Sea for 100,000 years and that even after a million year, the annual rate of release would be about 10^{-6} of the stored CO_2 per year.

Simulations designed to explore the possible release of stored CO_2 to the biosphere by multiple routes, including abandoned wells and other disturbances, have recently become available as a component of more general risk assessment activities (Section 6.5). Two studies of the Weyburn site, for example, assessed the probability of release to the biosphere. Walton *et al.* (2005) used a fully probabilistic model, with a simplified representation of CO_2 transport, to compute a probability distribution for the cumulative fraction released to the biosphere. Walton *et al.* found that after 5000 years, the probability was equal that the cumulative amount released would be larger or smaller than 0.1% (the median release fraction) and found a 95% probability that <1% of the total amount stored would be released. Using a deterministic model of CO_2 transport in the subsurface, Zhou *et al.* (2005) found no release to the biosphere in 5000 years. While using a probabilistic model of transport through abandoned wells, they found a statistical mean release of 0.001% and a maximum release of 0.14% (expressed as the cumulative fraction of stored CO_2 released over 5000 years).

In saline formations or oil and gas reservoirs with significant brine content, much of the CO_2 will eventually dissolve in the brine (Figure 8), be trapped as a residual immobile phase (Figure 9) or be immobilized by geochemical reactions. The time scale for dissolution is typically short compared to the time for CO_2 to migrate out of the storage formation by other processes (Ennis-King and Paterson, 2003; Lindeberg and Bergmo, 2003; Walton *et al.*, 2005). It is expected that many storage projects could be selected and operated so that a very large fraction of the injected CO_2 will dissolve. Once dissolved, CO_2 can eventually be transported out of the injection site by basin-scale circulation or upward migration, but the time scales (millions of years) of such transport are typically sufficiently long that they can (arguably) be ignored in assessing the risk of leakage.

As described in Section 2.4, several CO_2 storage projects are now in operation and being carefully monitored. While no leakage of stored CO_2 out of the storage formations has been observed in any of the current projects, time is too short and overall monitoring too limited, to enable direct empirical conclusions about the long-term performance of geological storage. Rather than providing a direct test of performance, the current projects improve the quality of long-duration performance predictions by testing and sharpening understanding of CO_2 transport and trapping mechanisms.

6.4.5 *Assessment of underground CO_2 retention*

Assessment of the fraction retained for geological storage projects is highly site-specific, depending on (1) the storage system design, including the geological characteristics of the selected storage site; (2) the injection system and related reservoir engineering; and (3) the methods of abandonment, including the performance of well-sealing technologies. If the above information is available, it is possible to estimate the fraction retained by using the models described in Section 4.2 and risk assessment methods described in Section 6.5. Therefore, it is also possible, in principle, to estimate the expected performance of an ensemble of storage projects that adhere to design guidelines such as site selection, seal integrity, injection depth and well closure technologies.

For large-scale operational CO_2 storage projects, assuming that sites are well selected, designed, operated and appropriately monitored, the balance of available evidence suggests the following (Walton *et al.*, 2005):

- It is very likely the fraction of stored CO_2 retained is more than 99% over the first 100 years.
- It is likely the fraction of stored CO_2 retained is more than 99% over the first 1000 years.

It is important to note that such probabilistic performance and risk assessment is primarily based on the experiences gained from storage of oil and natural gas reservoirs.

6.5 Possible local and regional environmental hazards

6.5.1 *Potential hazards to human health and safety*

Risks to human health and safety arise (almost) exclusively from elevated CO_2 concentrations in ambient air, either in confined outdoor environments, in caves or in buildings. Physiological and toxicological responses to elevated CO_2 concentrations are relatively well understood. At concentrations above about 2%, CO_2 has a strong effect on respiratory physiology and at concentrations above 7–10%, it can cause unconsciousness and death. Exposure studies have not revealed any adverse health effect of chronic exposure to concentrations below 1%.

The principal challenge in estimating the risks posed by CO_2 that might seep from storage sites lies in estimating the spatial and temporal distribution of CO_2 fluxes reaching the shallow subsurface and in predicting ambient CO_2 concentration resulting from a given CO_2 flux. Concentrations in surface air will be strongly influenced by surface topography and atmospheric conditions. Because CO_2 is 50% denser than air, it tends to migrate downwards, flowing along the ground and collecting in shallow depressions, potentially creating much higher concentrations in confined spaces than in open terrain.

Seepage of CO_2 is not uncommon in regions influenced by volcanism. Naturally occurring releases of CO_2 provide a basis for understanding the transport of CO_2 from the vadose zone to the atmosphere, as well as providing empirical data that link CO_2 fluxes into the shallow subsurface with CO_2 concentrations in the ambient air – and the consequent health and safety risks. Such seeps do not, however, provide a useful basis for estimating the spatial and temporal distribution of CO_2 fluxes leaking from a deep storage site, because (in general) the seeps occur in highly fractured volcanic zones, unlike the interiors of stable sedimentary basins, the likely locations for CO_2 storage (Section 2.2).

Natural seeps are widely distributed in tectonically active regions of the world (Morner and Etiope, 2002). In central Italy, for example, CO_2 is emitted from vents, surface degassing and diffuse emission from CO_2-rich groundwater. Fluxes from vents range from less than 100 to more than 430 tCO_2 day^{-1}, which have shown to be lethal to animal and plants. At Poggio dell'Ulivo, for example, a flux of 200 tCO_2 day^{-1} is emitted from diffuse soil degassing. At least ten people have died from CO_2 releases in the region of Lazio over the last 20 years.

Natural and engineered analogues show that it is possible, though improbable, that slow releases from CO_2 storage reservoirs will pose a threat to humans. Sudden, catastrophic releases of natural accumulations of CO_2 have occurred, associated with volcanism or subsurface mining activities. Thus, they are of limited relevance to understanding risks arising from CO_2 stored in sedimentary basins. However, mining or drilling in areas with CO_2 storage sites may pose a long-term risk after site abandonment if institutional knowledge and precautions are not in place to avoid accidentally penetrating a storage formation.

*6.5.2 **Hazards to groundwater from CO_2 leakage and brine displacement***

Increases in dissolved CO_2 concentration that might occur as CO_2 migrates from a storage reservoir to the surface will alter groundwater chemistry, potentially affecting shallow groundwater used for potable water and industrial and agricultural needs. Dissolved CO_2 forms carbonic acid, altering the pH of the solution and potentially causing indirect effects, including mobilization of (toxic) metals, sulphate or chloride; and possibly giving the water an odd odour, colour or taste. In the worst case, contamination might reach dangerous levels, excluding the use of groundwater for drinking or irrigation.

The injection of CO_2 or any other fluid deep underground necessarily causes changes in pore-fluid pressures and in the geomechanical stress fields that reach far beyond the volume occupied by the injected fluid. Brines displaced from deep formations by injected CO_2 can potentially migrate or leak through fractures or defective wells to shallow aquifers and contaminate shallower drinking water formations by increasing their salinity. In the worst case, infiltration of saline water into groundwater or into the shallow subsurface could impact wildlife habitat, restrict or eliminate agricultural use of land and pollute surface waters.

6.5.3 *Hazards to terrestrial and marine ecosystems*

Stored CO_2 and any accompanying substances, may affect the flora and fauna with which it comes into contact. Impacts might be expected on microbes in the deep subsurface and on plants and animals in shallower soils and at the surface. The remainder of this discussion focuses only on the hazards where exposures to CO_2 do occur. As discussed in Section 6.3, the probability of leakage is low. Nevertheless, it is important to understand the hazards should exposures occur.

In the last three decades, microbes dubbed 'extremophiles', living in environments where life was previously considered impossible, have been identified in many underground habitats. These microorganisms have limited nutrient supply and exhibit very low metabolic rates (D'Hondt *et al.*, 2002). Recent studies have described populations in deep saline formations (Haveman and Pedersen, 2001); oil and gas reservoirs (Orphan *et al.*, 2000) and sediments up to 850 m below the sea floor (Parkes *et al.*, 2000). The mass of subsurface microbes may well exceed the mass of biota on the Earth's surface (Whitman *et al.*, 2001). The working assumption may be that unless there are conditions preventing it, microbes can be found everywhere at the depths being considered for CO_2 storage and consequently CO_2 storage sites may generally contain microbes that could be affected by injected CO_2.

The effect of CO_2 on subsurface microbial populations is not well studied. A low-*p*H, high-CO_2 environment may favour some species and harm others. In strongly reducing environments, the injection of CO_2 may stimulate microbial communities that would reduce the CO_2 to CH4; while in other reservoirs, CO_2 injection could cause a short-term stimulation of Fe (III)-reducing communities (Onstott, 2005). From an operational perspective, creation of biofilms may reduce the effective permeability of the formation.

Should CO_2 leak from the storage formation and find its way to the surface, it will enter a much more biologically active area. While elevated CO_2 concentrations in ambient air can accelerate plant growth, such fertilization will generally be overwhelmed by the detrimental effects of elevated CO_2 in soils, because CO_2 fluxes large enough to significantly increase concentrations in the free air will typically be associated with much higher CO_2 concentrations in soils. The effects of elevated CO_2 concentrations would be mediated by several factors: the type and density of vegetation; the exposure to other environmental stresses; the prevailing environmental conditions like wind speed and rainfall; the presence of low-lying areas; and the density of nearby animal populations.

The main characteristic of long-term elevated CO_2 zones at the surface is the lack of vegetation. New CO_2 releases into vegetated areas cause noticeable die-off. In those areas where significant impacts to vegetation have occurred, CO_2 makes up about 20–95% of the soil gas, whereas normal soil gas usually contains about 0.2–4% CO_2. Carbon dioxide concentrations above 5% may be dangerous for vegetation and as concentration approach 20%, CO_2 becomes phytotoxic. Carbon dioxide can cause death of plants through 'root anoxia', together with low oxygen concentration (Leone *et al.*, 1977; Flower *et al.*, 1981). One example of plant die-off occurred at Mammoth Mountain, California, USA, where a resurgence of volcanic activity resulted in high CO_2 fluxes.

There is no evidence of any terrestrial impact from current CO_2 storage projects. Likewise, there is no evidence from EOR projects that indicate impacts to vegetation such as those described above. However, no systematic studies have occurred to look for terrestrial impacts from current EOR projects. Natural CO_2 seepage in volcanic regions, therefore, provides examples of possible impacts from leaky CO_2 storage, although (as mentioned in Section 6.3) seeps in volcanic provinces provide a poor analogue to seepage that would occur from CO_2 storage sites in sedimentary basins.

The relevance of these natural analogues to leakage from CO_2 storage varies. For examples presented here, the fluxes and therefore the risks are much higher than might be expected from a CO_2 storage facility: the annual flow of CO_2 at the Mammoth Mountain site is roughly equal to a release rate on the order of 0.2% yr-1 from a storage site containing 100 $MtCO_2$. This corresponds to a fraction retained of 13.5% over 1000 years and, thus, is not representative of a typical storage site.

Seepage from offshore geological storage sites may pose a hazard to benthic environments and organisms as the CO_2 moves from deep geological structures through benthic sediments to the ocean. While leaking CO_2 might be hazardous to the benthic environment, the seabed and overlying seawater can also provide a barrier, reducing the escape of seeping CO_2 to the atmosphere. No studies specifically address the environmental effects of seepage from sub-seabed geological storage sites.

6.5.4 ***Induced seismicity***

Underground injection of CO_2 or other fluids into porous rock at pressures substantially higher than formation pressures can induce fracturing and movement along faults (Healy *et al.*, 1968; Gibbs *et al.*, 1973; Raleigh *et al.*, 1976; Sminchak *et al.*, 2002; Streit *et al.*, 2005; Wo *et al.*, 2005). Induced fracturing and fault activation may pose two kinds of risks. First, brittle failure and associated microseismicity induced by over pressuring can create or enhance fracture permeability, thus providing pathways for unwanted CO_2 migration (Streit and Hillis, 2003). Second, fault activation can, in principle, induce earthquakes large enough to cause damage (e.g., Healy *et al.*, 1968).

Fluid injection into boreholes can induce microseismic activity, as for example at the Rangely Oil Field in Colorado, USA (Gibbs *et al.*, 1973; Raleigh *et al.*, 1976), in test sites such as the drillholes of the German continental deep drilling programme (Shapiro *et al.*, 1997; Zoback and Harjes, 1997) or the Cold Lake Oil Field, Alberta, Canada (Talebi *et al.*, 1998). Deep-well injection of waste fluids may induce earthquakes with moderate local magnitudes (M_L), as suggested for the 1967 Denver earthquakes (M_L of 5.3; Healy *et al.*, 1968; Wyss and Molnar, 1972) and the 1986–1987 Ohio earthquakes (M_L of 4.9; Ahmad and Smith, 1988) in the United States. Seismicity induced by fluid injection is usually assumed to result from increased pore-fluid pressure in the hypocentral region of the seismic event (e.g., Healy *et al.*, 1968; Talebi *et al.*, 1998).

Readily applicable methods exist to assess and control induced fracturing or fault activation. Several geomechanical methods have been identified for assessing the stability of faults and estimating maximum sustainable pore-fluid pressures for CO_2 storage (Streit and Hillis, 2003). Such methods, which require the determination of *in situ* stresses, fault geometries and relevant rock strengths, are based on brittle failure criteria and have been applied to several study sites for potential CO_2 storage (Rigg *et al.*, 2001; Gibson-Poole *et al.*, 2002).

The monitoring of microseismic events, especially in the vicinity of injection wells, can indicate whether pore fluid pressures have locally exceeded the strength of faults, fractures or intact rock. Acoustic transducers that record microseismic events in monitoring wells of CO_2

storage sites can be used to provide real-time control to keep injection pressures below the levels that induce seismicity. Together with the modelling techniques mentioned above, monitoring can reduce the chance of damage to top seals and fault seals (at CO_2 storage sites) caused by injection-related pore-pressure increases.

Fault activation is primarily dependent on the extent and magnitude of the pore-fluid-pressure perturbations. It is therefore determined more by the quantity and rate than by the kind of fluid injected. Estimates of the risk of inducing significant earthquakes may therefore be based on the diverse and extensive experience with deep-well injection of various aqueous and gaseous streams for disposal and storage. Perhaps the most pertinent experience is the injection of CO_2 for EOR; about 30 $MtCO_2$ yr-1 is now injected for EOR worldwide and the cumulative total injected exceeds 0.5 $GtCO_2$, yet there have been no significant seismic effects attributed to CO_2-EOR. In addition to CO_2, injected fluids include brines associated with oil and gas production (>2 Gt yr^{-1}); Floridan aquifer wastewater (>0.5 Gt yr^{-1}); hazardous wastes (>30 Mt yr^{-1}); and natural gas (>100 Mt yr^{-1}) (Wilson *et al.*, 2003).

While few of these cases may precisely mirror the conditions under which CO_2 would be injected for storage (the peak pressures in CO_2-EOR may, for example, be lower than would be used in formation storage), these quantities compare to or exceed, plausible flows of CO_2 into storage. For example, in some cases such as the Rangely Oil Field, USA, current reservoir pressures even exceed the original formation pressure (Raleigh *et al.*, 1976). Thus, they provide a substantial body of empirical data upon which to assess the likelihood of induced seismicity resulting from fluid injection. The fact that only a few individual seismic events associated with deep-well injection have been recorded suggests that the risks are low. Perhaps more importantly, these experiences demonstrate that the regulatory limits imposed on injection pressures are sufficient to avoid significant injection-induced seismicity. Designing CO_2 storage projects to operate within these parameters should be possible.
Nevertheless, because formation pressures in CO_2 storage formations may exceed those found in CO_2-EOR projects, more experience with industrial-scale CO_2 storage projects will be needed to fully assess risks of microseismicity.

6.5.5 *Implications of gas impurity*

Under some circumstances, H_2S, SO_2, NO_2 and other trace gases may be stored along with CO_2 (Bryant and Lake, 2005; Knauss *et al.*, 2005) and this may affect the level of risk. For example, H_2S is considerably more toxic than CO_2 and well blow-outs containing H_2S may present higher risks than well blow-outs from storage sites that contain only CO_2. Similarly, dissolution of SO_2 in groundwater creates a far stronger acid than does dissolution of CO_2; hence, the mobilization of metals in groundwater and soils may be higher, leading to greater risk of exposure to hazardous levels of trace metals. While there has not been a systematic and comprehensive assessment of how these additional constituents would affect the risks associated with CO_2 storage, it is worth noting that at Weyburn, one of the most carefully monitored CO_2 injection projects and one for which a considerable effort has been devoted to risk assessment, the injected gas contains approximately 2% H_2S (Wilson and Monea, 2005). To date, most risk assessment studies have assumed that only CO_2 is stored; therefore, insufficient information is available to assess the risks associated with gas impurities at the present time.

6.6 Risk management

Risk management entails the application of a structured process to identify and quantify the risks associated with a given process, to evaluate these, taking into account stakeholder input and context, to modify the process to remove excess risks and to identify and implement appropriate monitoring and intervention strategies to manage the remaining risks.

For geological storage, effective risk mitigation consists of four interrelated activities:

- Careful site selection, including performance and risk assessment (Chapter 4) and socio-economic and environmental factors;
- Monitoring to provide assurance that the storage project is performing as expected and to provide early warning in the event that it begins to leak (Chapter 5);
- Effective regulatory oversight (not discussed);
- Implementation of remediation measures to eliminate or limit the causes and impacts of leakage (Section 6.7).

Risk management strategies must use the inputs from the risk assessment process to enable quantitative estimates of the degree of risk mitigation that can be achieved by various measures and to establish an appropriate level of monitoring, with intervention options available if necessary. Experience from natural gas storage projects and disposal of liquid wastes has demonstrated the effectiveness of this approach to risk mitigation (Wilson *et al.*, 2003; Apps, 2005; Perry, 2005).

6.7 Remediation of leaking storage projects

Geological storage projects will be selected and operated to avoid leakage. However, in rare cases, leakage may occur and remediation measures will be needed, either to stop the leak or to prevent human or ecosystem impact. Moreover, the availability of remediation options may provide an additional level of assurance to the public that geological storage can be safe and effective. While little effort has focused on remediation options thus far, Benson and Hepple (2005) surveyed the practices used to remediate natural gas storage projects, groundwater and soil contamination, as well as disposal of liquid waste in deep geological formations. On the basis of these surveys, remediation options were identified for most of the leakage scenarios that have been identified, namely:

- Leaks within the storage reservoir;
- Leakage out of the storage formation up faults and fractures;
- Shallow groundwater;
- Vadose zone and soil;
- Surface fluxes;
- CO_2 in indoor air, especially basements;
- Surface water.

Table 4. Remediation options for geological CO_2 storage projects (after Benson and Hepple, 2005).

Scenario	**Remediation options**
Leakage up faults, fractures and spill points	• Lower injection pressure by injecting at a lower rate or through more wells (Buschbach and Bond, 1974); • Lower reservoir pressure by removing water or other fluids from the storage structure; • Intersect the leakage with extraction wells in the vicinity of the leak; • Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak; • Lower the reservoir pressure by creating a pathway to access new compartments in the storage reservoir; • Stop injection to stabilize the project; • Stop injection, produce the CO2 from the storage reservoir and reinject it back into a more suitable storage structure.
Leakage through active or abandoned wells	• Repair leaking injection wells with standard well recompletion techniques such as replacing the injection tubing and packers; • Repair leaking injection wells by squeezing cement behind the well casing to plug leaks behind the casing; • Plug and abandon injection wells that cannot be repaired by the methods listed above; • Stop blow-outs from injection or abandoned wells with standard techniques to 'kill' a well such as injecting a heavy mud into the well casing. After control of the well is re-established, the recompletion or abandonment practices described above can be used. If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and 'kill' the well by pumping mud down the interception well (DOGGR, 1974).
Accumulation of CO2 in the vadose zone and soil gas	• Accumulations of gaseous CO2 in groundwater can be removed or at least made immobile, by drilling wells that intersect the accumulations and extracting the CO2. The extracted CO2 could be vented to the atmosphere or reinjected back into a suitable storage site; • Residual CO2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase through groundwater extraction well; • CO2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO2. The groundwater could then either be used directly or reinjected back into the groundwate; • If metals or other trace contaminants have been mobilized by acidification of the groundwater, 'pump-and-treat' methods can be used to remove them. Alternatively, hydraulic barriers can be created to immobilize and contain the contaminants by appropriately placed injection and extraction wells. In addition to these active methods of remediation, passive methods that rely on natural biogeochemical processes may also be used.
Leakage into the vadose zone and accumulation in soil gas (Looney and Falta, 2000)	• CO2 can be extracted from the vadose zone and soil gas by standard vapor extraction techniques from horizontal or vertical wells; • Fluxes from the vadose zone to the ground surface could be decreased or stopped by caps or gas vapour barriers. Pumping below the cap or vapour barrier could be used to deplete the accumulation of CO2 in the vadose zone; • Since CO2 is a dense gas, it could be collected in subsurface trenches. Accumulated gas could be pumped from the trenches and released to the atmosphere or reinjected back underground; • Passive remediation techniques that rely only on diffusion and 'barometric pumping' could be used to slowly deplete one-time releases of CO2 into the vadose zone. This method will not be effective for managing ongoing releases because it is relatively slow; • Acidification of the soils from contact with CO2 could be remediated by irrigation and drainage. Alternatively, agricultural supplements such as lime could be used to neutralize the soil;
Large releases of CO2 to the atmosphere	• For releases inside a building or confined space, large fans could be used to rapidly dilute CO2 to safe levels; • For large releases spread out over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting the CO2; • For ongoing leakage in established areas, risks of exposure to high concentrations of CO2 in confined spaces (e.g. cellar around a wellhead) or during periods of very low wind, fans could be used to keep the rate of air circulation high enough to ensure adequate dilution.
Accumulation of CO2 in indoor environments with chronic low level leakage	• Slow releases into structures can be eliminated by using techniques that have been developed for controlling release of radon and volatile organic compounds into buildings. The two primary methods for managing indoor releases are basement/substructure venting or pressurization. Both would have the effect of diluting the CO2 before it enters the indoor environment (Gadgil *et al.*, 1994; Fischer *et al.*, 1996).
Accumulation in surface water	• Shallow surface water bodies that have significant turnover (shallow lakes) or turbulence (streams) will quickly release dissolved CO2 back into the atmosphere; • For deep, stably stratified lakes, active systems for venting gas accumulations have been developed and applied at Lake Nyos and Monoun in Cameroon (http://perso.wanadoo.fr/mhalb/nyos/).

Identifying options for remediating leakage of CO_2 from active or abandoned wells is particularly important, because they are known vulnerabilities (Gasda *et al.*, 2004; Perry, 2005). Stopping blow-outs or leaks from injection or abandoned wells can be accomplished with standard techniques, such as injecting a heavy mud into the well casing. If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and then pump mud down into the interception well. After control of the well is re-established, the well can be repaired or abandoned. Leaking injection wells can be repaired by replacing the injection tubing and packers. If the annular space behind the casing is leaking, the casing can be perforated to allow injection (squeezing) of cement behind the casing until the leak is stopped. If the well cannot be repaired, it can be abandoned by following the procedure outlined (IPCC, 2005; Section 5.5.2)

Table 4 provides an overview of the remediation options available for the leakage scenarios listed above. Some methods are well established, while others are more speculative. Additional detailed studies are needed to further assess the feasibility of applying these to geological storage projects – studies that are based on realistic scenarios, simulations and field studies.

7 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, are summaries what are known now and what gaps remain. Gaps in the knowledge of geological storage of CO_2 are presented in this report according to the rating on the scale (1-5) given in the Review of SRCCS Gaps in Knowledge (IPCC, 2006). The scales are as outline below:

1 Very important and needs to be addressed to move the technology towards full scale implementation.
2 Important and needs to be addressed with some urgency
3 Less important but needs to be undertaken
4 Not important – CCS can be implemented without this gap being addressed or gap will be addressed through natural development
5 Unimportant – gap does not need to be addressed

At present there are no knowledge gaps that hinder full scale implementation of geological storage of CO_2 (1). Important gaps in knowledge that need to be addressed with some urgency (2) are:

A) Storage Capacity

- Need to get universal agreement on a storage capacity assessment method, particularly for aquifers. This knowledge is needed to determine effective capacity for CO_2 storage in geological formations to derive policy and research initiatives.
- Need a full global data set – presently most data set is from Australian, Japan, North America and West Europe.

B) Improved Confidence

- Risks of leakage from abandoned wells and methods of leakage need to be determined.
- Assess the environmental impact of CO_2 seepage on the marine seafloor.
- Quantitative assessment of risks to human health required.
- Quantification of all processes related to CO_2 migration/leakage rates as well as geochemical reactions (in cements, caprock and reservoirs) including the calibration of these models both in lab and real injection tests from more storage sites or projects.
- Develop reliable coupled hydrogeological-geochemical-geomechanical simulation models to use as a prediction tools.

C) Monitoring Techniques

- Improve fracture detection and characterization of leakage potential.

D) Cost

- Only a few experience-based cost data from non CO_2-EOR storage sites are available, more would be useful

E) *Regulation and Liability*

- Framework has yet to be established, however, it should consider: the role of pilot projects, Verification of CO_2 storage for accounting purposes, approaches for selecting, operation and monitoring CO_2 storage sites in the short and long term stewardship and requirements for decommissioning a storage project.

Knowledge gaps on geological storage of CO_2 which are less important but needs to be undertaken (3) include:

- *Storage mechanisms* - determining the kinetics of geochemical trapping and the long term effects of CO_2 on reservoir fluids and rocks, in particular any adverse geochemical effects that might occur to reduce the integrity of the cap rock. Knowledge on such a topic is growing (see Section 8.4) and is continuing to develop with time.
- *Monitoring techniques* – need improved quantification and resolution of CO_2 in the subsurface, improved detection and monitoring of subsurface CO_2 seepage, remote sensing and cost-effective surface methods for temporally variable leak detection and quantification must be developed, and finally development of long-term monitoring strategies required.
- *Leakage remediation* – no present examples of remediation for leaked CO_2, it might be valuable to have an engineered, controlled, leakage event that can be used as a learning experience.
- *Cost* – little knowledge of regulatory compliance costs, therefore, there is a need to develop regulatory process needs to determine costs.

Unimportant (5) knowledge gaps on geological storage of CO_2 do not need to be addressed. However, knowledge gaps that are not important (4) because CCS can either be implemented without this gap or the gap becomes addressed during the process include:

- Determining microbial impacts in the deep subsurface.
- Assess the temporal and spatial variability of leaks arising from inadequate storage sites.
- Further knowledge is needed on history of natural accumulations of CO_2.

8 Case study - The Sleipner Gas field

8.1 Background

8.1.1 Offshore geology

The geology of the Norwegian continental shelf is varied; both with respect to age and rock/sediment type (Sigmond 1992). The areas of the present continental shelf were strongly influenced by the Caledonian Orogeny 500-400 million years ago. The Devonian, ca. 400-350 million years ago, was a period of collapse, erosion and molasse sedimentation of the orogen.

Thick sedimentary units were deposited in Carboniferous (~345-300 million years) and Permian (~280-250 million years) times on Svalbard and in the Barents Sea (Figure 17a). The Permian was a period of extensive stretching of the continental crust, widespread faulting and deposition of thick sedimentary successions, especially in the Skagerrak, in the North Sea and off Mid-Norway (Figure 17a). Skagerrak experienced significant volcanic activity associated with rifting. In the Triassic (~240-185 million years), thick sedimentary units were deposited in the Barents Sea, on the Trøndelag Platform and in the North Sea (Figure 17a). In the North Sea and the Norwegian Sea this was accompanied by extensive normal faulting.

Extensive rifting and normal faulting occurred in the North Sea and the Norwegian Sea in the Jurassic (~180-135 million years), and source rocks and reservoir rocks very important for the Norwegian hydrocarbon production were deposited. Other phases of rifting and normal faulting, in the Cretaceous (~135-65 million years) and Tertiary (~65-3 million years), were associated with extension leading to opening of the North Atlantic Ocean. Especially during Cretaceous times sedimentary successions approaching 10 kilometers in thickness were deposited in the Møre and Vøring Basins. Cretaceous rocks are widespread on the Norwegian continental shelf.

In the Pliocene (~14 million years) and Pleistocene (~2 - 0.5 million years), the continental shelf was strongly influenced by glacial processes. Major uplift and erosion took place on the Norwegian mainland, in the Barents Sea, and in the Skagerrak area. The erosional products occur as large slope aprons along the continental margin, especially off the Svalbard-Barents Sea margin (thickness of several kilometers), and in the Norwegian Sea off Mid-Norway and in the Møre Basin (Figure 17b).

Figure 17a: Map of Norway showing names of places and hydrocarbon fields, modified after NGU 2002.

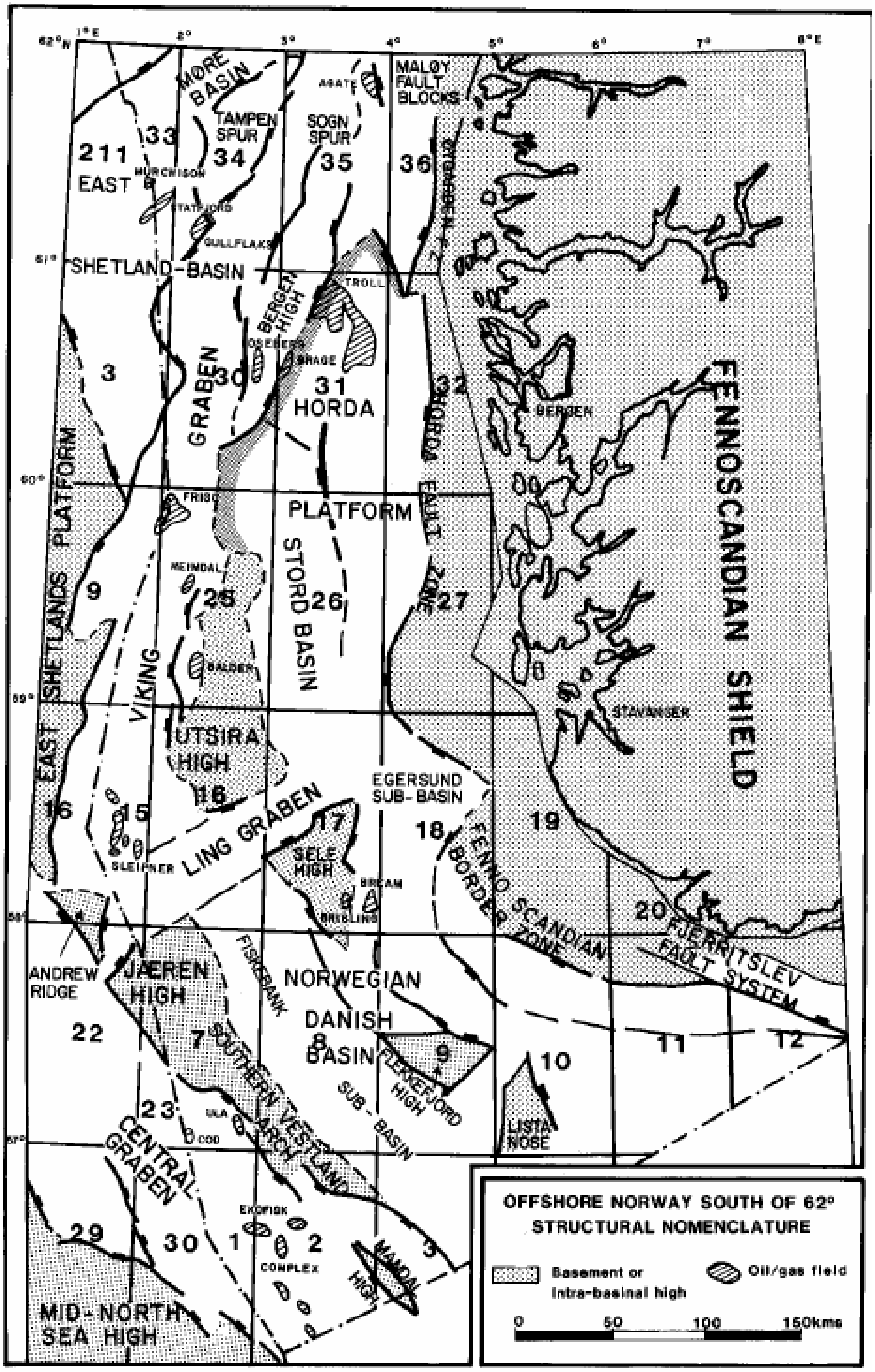

Figure 17b: Structural nomenclature offshore Norway south of 62_N. (Source NGU)

8.1.2 Utsira Formation

The Utsira Formation was deposited during the late Middle Miocene (~20 million years) to Early Pliocene (~14 million years), Eidvin et al. 2002. The formation belongs to the Nordland Group present in the Viking Graben (Gregersen and Michelsen 1997), area from ca. 58ºN to 62ºN (Figure 18). The Utsira formation is a highly elongated sand reservoir, extending for more than 400 km from north to south and between 50 and 100 km from east to west, with an area of some 26 100 km^2. The top Utsira formation and surface generally varies relatively smoothly, mainly in the range 550 to 1500 m, but mostly from 700 to 1000 m. There are two main depocentres. One is in the south, around Sleipner, where thicknesses range up to more than 300 m. The second depocentre lies some 200 km to the north of Sleipner. There the Utsira formation is locally 200 m thick, with an underlying sandy unit adding further to the total reservoir thickness (Chadwick *et al.,* 2000). At the nearest the formation, lies some 60-70 km, from the Norwegian coast.

From well logs in Eidvin et al. (2002) it is estimated that 70% of the Utsira Formation is made of sand/sandstone. The Utsira Formation is overlain by Pliocene marine claystones of the upper part of the Nordland Group. The cap rock succession overlying the Utsira formation is rather variable, and can be divided into three main units, the lower, the middle and the upper seal (Torp and Gale, 2003). The lower seal extends well beyond the area currently occupied by the CO_2 injected at Sleipner and seems to be providing an effective seal at the present time (Figure 19). Empirically, therefore, the caprock samples suggest the presence of an effective seal at Sleipner, with capillary leakage of CO_2 unlikely to occur (Chadwick *et al.,* 2000). The claystones are grey, sometimes greenish-grey and grey-brown, soft, sometimes silty and micaceous. The uppermost part of the Nordland Group consists of Pleistocene unconsolidated clays and sands, with glacial deposits uppermost (Isaksen and Tonstad 1989). The thickness of the seal is 500-1500 m. The seal on top of the Utsira Formation is assumed to be continuous across the area. In the east, the rocks are inclined such that stored CO_2 would migrate eastwards and up towards the Pleistocene boundary.

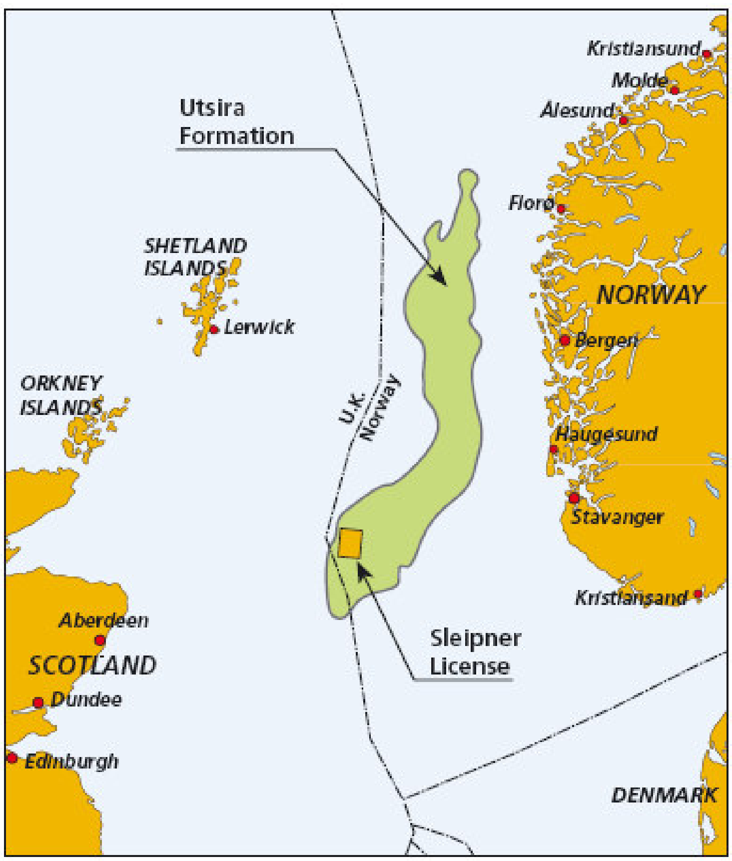

Figure 18: Location map showing areal extent of the Utsira Formation and the Sleipner licence.

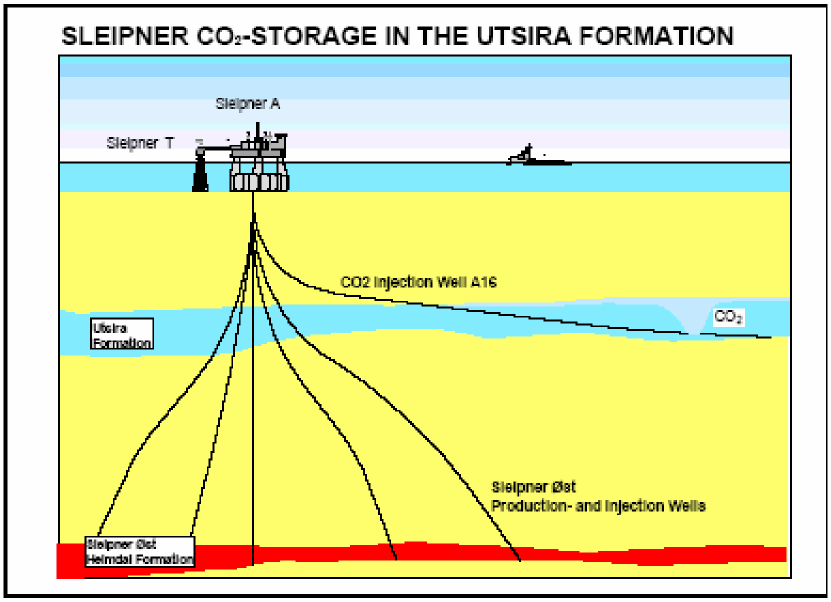

Figure 19: The Sleipner CO_2 injection scheme. The Utsira formation is a 200 -250 meters thick and very permeable sandstone overlaid with mudstone. The CO_2 capture takes place at the Sleipner T (Treatment) platform where it is also compressed. The highly deviated injection well has been drilled from the nearby Sleipner A concrete platform. (Source Statoil)

Macroscopic and microscopic analysis of core and cuttings samples of the Utsira formation show that it consists of largely uncemented fine-grained sand, with medium and occasional coarse grains. Porosity estimates of the Utsira formation core based on microscopy range generally from 27% to 31%, locally up to 42%. Laboratory experiments on the core give porosities between 35 and 42.5% (Chadwick *et al.,* 2000).

*8.1.3 **Saline Aquifer Carbon dioxide Storage (SACS) Project***

The SACS project was a research and demonstration project which is monitoring and forward modelling the underground CO_2 sequestration operation taking place at the Sleipner West gas field, offshore Norway.

The offshore gas field Sleipner, in the middle of the North Sea, has been injecting 1 Mt CO_2 per year since September 1996 (Baklid *et al.,* 1996). The CO_2 is injected into salt water containing sand layer, called the Utsira formation, which lies 1000 meter below sea bottom. During 1998, a group of energy companies together with scientific institutes and environmental authorities in Norway, Denmark, the Netherlands, France and the UK formed the Saline Aquifer CO_2 Storage (SACS) Project Consortium and started to collect relevant information about the injection of CO_2 into the Utsira formation and similar underground structures around the North Sea. The SACS project involves a multidisciplinary approach. The different scientific disciplines involved in the project include: geology, geochemistry, geophysics and reservoir engineering/simulation.

In 1999 the SACS (Phase 1) project (supported under the European Commission's Thermie Programme) started monitoring the CO_2 behaviour and established a baseline by shooting a first 3D seismic survey (Gale *et al*, 2001), . The Phase 1 Project was extended to SACS2 in 2000 again with European Commission (EC) support. The SACS2 project, which terminated in 2003, continued the work undertaken in Phase 1 with further repeat 3D seismic surveys completed to track the fate of the injected CO_2. In addition, it is using the seismic data to verify available models and tools originally developed for hydrocarbons and water that have been applied to a CO_2 and water system (Section 5.2.2). The major difference being that CO_2 is soluble in water and methane is not.

The goal of the SACS2 project was to develop a consensus about the monitoring results and validity of available models and tools. To develop such a consensus involves close co-ordination between the scientific institutes involved in the project. The cumulative experiences of the SACS projects are presented in a Best Practice Manual to assist other organisations planning CO_2 injection projects to take advantage of the learning processes undertaken and to assist in facilitating new projects of this type. The document Best Practice Manual (Best Practice Manual, 2004) outlines the main findings of the SACS projects and this report reviews the document in this chapter.

*8.1.4 **CO_2 storage quality and capacity***

During the SACS-project, it has been shown that the Utsira Formation has good storage quality with respect to porosity, permeability, mineralogy, bedding, depth, pressure and temperature (e.g. Zweigel and Lindeberg 2000). It is a very large aquifer with a thick and extensive claystone top seal. The aquifer is, however, unconfined along its margins, and the time before migrating CO_2 might reach the margins of the aquifer is unknown. The Utsira Formation is regarded as one of the most promising aquifers for CO_2 storage in Europe. It has both such a considerable thickness and extent that it alone could store the CO_2 emissions from all of the north European power stations and other large industrial plants for several hundred years (Torp & Christensen 1998). It is estimated that the Utsira Formation, below 800 m depth, has a pore volume of 918 km^3, a storage capacity in traps of 847 Mt (mega tonnes) CO_2, and that the storage capacity of the entire aquifer is 42 356 Mt CO_2 with an assumption that storage volume representing 3 % the pore volume (See details in Bøe et al. 2002, Table 6). The total pore volume of the aquifer is, however, estimated differently by other workers, 6.05×10^{11} m^3 (Kirby *et al.* 2001) and 5.5×10^{11} m^3 (Chadwick et al. 2000).

8.2 Geological Suitability

Saline formations are deep sedimentary rocks saturated with formation waters or brines containing high concentrations of dissolved salts. Geological storage of carbon dioxide in deep saline aquifers is likely to be safe provided the following conditions are met.

(1) adequate capacity and injectivity,
(2) a satisfactory sealing caprock or confining unit and
(3) a sufficiently stable geological environment to avoid compromising the integrity of the storage site.

In general, geological storage sites should meet all these conditions.

Among the most important geological criteria set for safe storing are: (1) basin characteristics (tectonic activity, sediment type, geothermal and hydrodynamic regimes); (2) basin resources (hydrocarbons, coal, salt); (3) industry maturity and infrastructure; and (4) societal issues such as level of development, economy, environmental concerns, public education and attitudes.

The suitability of sedimentary basins for CO_2 storage depends in part on their location on the continental plate. Basins formed in mid-continent locations or near the edge of stable continental plates, are excellent targets for long-term CO_2 storage because of their stability and structure. Such basins are found within most continents and around the Atlantic, Arctic and Indian Oceans. The Utsira formation is typical with this regards because it is located in tectonically stable zone. Geological suitability in the Utsira formation for CO_2 storage is likely to be good for the following reasons

(1) suitable sedimentary formation with 800 - 1000 m thickness
(2) have good reservoir and seal relationships
(3) absence of highly faulted and fractured formations
(4) is not within fold belts with absence of overpressured reservoirs
(5) the sand formation have not undergone significant diagenesis
(6) have adequate porosity and thickness (for storage capacity) and permeability (for injectivity)
(7) is conducive to hydrodynamic and mineral trapping because of long residence times (Section 3.2).

8.3 Tasks accomplished

This part consists of the tasks accomplished at Sleipner CO_2 sequestration operation during the SACS project and the experiences of monitoring the carbon dioxide storage. Four main work areas of the SACS project include:

- Microseismic studies
- Characterisation of the reservoir and caprock
- Monitoring the CO_2 injection process
- Reservoir simulation and
- Geochemical characterisation

*8.3.1 **Micoseismic studies***

The natural state of stress due to the geological setting, the mechanical properties of the reservoir rocks and host rocks, and the changes in pore pressure due to fluid withdrawal or injection are the principal causes of induced seismisity in a reservoir in which there is fluid movement. Detailed study on the literature review of the state of stress in the North Sea as well as observations on the occurrence of microseismisity is presented in SACS-Feasibility study of microseismic monitoring (Fabriol, 2001). Here the main conclusions drawn from the study follow.

The study suggests that the conditions that could promote seismic slip along natural faults or fractures at Sleipner include: the regional compressive stress regime, because of which faults, whether present and depending on their orientation with respect to the maximum horizontal stress (S_{Hmax}), can be critically stressed fractures; the slight overpressure due to injection of CO_2, which is added to the hydrostatic pressure, Carlsen *et al.* (2001) predict an overpressure of 0.02 MPa due to the accumulation of CO_2 in the space confined by the caprock; and stress variations as slight as 0.02 MPa (in compressive region), are common examples of triggering failure (e.g. King *et al.*, 1994).

However, these conditions are offset by the following:

- Mechanical characteristics below 1500 m depth: according to Grollimund *et al.* (2000), sediments are not sufficiently consolidated to support stress, which is in keeping with the porosity values over 27% and permeability over 1D in the Utsira Formation
- The question of whether faults actually exist in and above the Utsira Formation. A priori, the apparent structures are due to mud volcanoes and intraformational faults are more likely to affect the underlying Oligocene sediments (as in the Troll field northeast of Sleipner)

As a rule, the injection of the CO_2 in sands of the Utsira Formation should not trigger any measurable microseismicity except in impermeable or semi-permeable shale lenses that block the rise of the CO_2 toward the top of the formation. This could be an indication of the presence of CO_2 insofar as it would allow the detection of the conduits used for CO_2 migration. The start of this passage still has to be established in order to define the advance of the CO_2 front. Similarly, microseismicity may appear at the top of the formation. This could be an evidence of the initiation of open fractures that could subsequently give rise to leakage.

8.3.2 ***Characterisation of the reservoir***

It is necessary to characterise the reservoir and caprock on both local and regional scales to elucidate CO_2 migration patterns and overall storage potential. This involves a determination of structure and stratigraphy both within and external to the reservoir, together with the physical properties of both the reservoir and caprock.

Characterisation of both the reservoir and caprock was carried out at a range of scales. Several datasets were available to the SACS project (See Best Practice Manual, 2004 for details). The datasets were used to characterize the reservoir both at the regional and local level. The whole reservoir (some 26000 km^2) was mapped and characterised using regional 2D seismic datasets and well data. More detailed work was carried out around the injection site using a 3D seismic dataset and more closely spaced well data. The 2D and 3D seismic data constituted the key datasets, essential for delineating the reservoir limits, structure and stratigraphical correlation (Figure 20a). A large number of wells was useful for delineating regional structure, and was essential for mapping reservoir properties, such as porosity. Of the available geophysical logs, the γ-ray log was the most useful general-purpose tool for identifying the reservoir sand and quantifying sand/shale ratios, augmented by the resistivity log. Sonic and density logs were utilised for porosity determination and mapping. In addition to analysis of seismic and borehole data, rock material (core and cuttings) data were used to characterize the properties of a reservoir in the subsurface. This was aimed to produce information on structure, stratigraphy and physical properties. The mapping included, as a minimum, depth to top reservoir, reservoir thickness and reservoir physical properties (porosity and sand/shale ratio if appropriate). It is also essential to understand the lateral and vertical stratigraphical and hydraulic continuity of the reservoir.

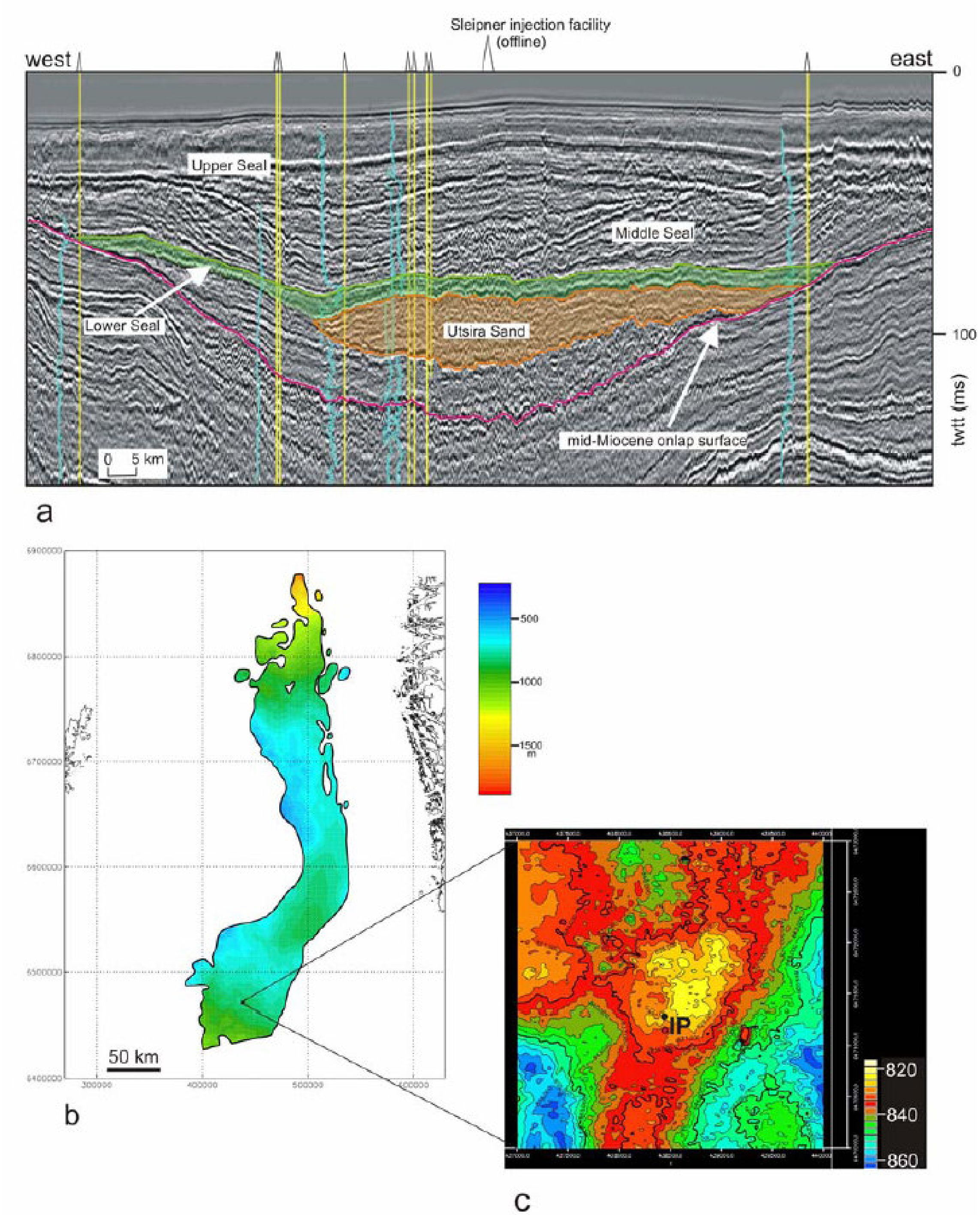

Figure 20 a) Typical 2D seismic reflection profile across the Utsira reservoir b) Regional depth map to top Utsira Sand based on 2D seismic surveys and incorporating 3D data around Sleipner injection point. c) Detailed depth map of Top Utsira Sand around Sleipner injection point (IP), based on 3D seismic data. [2D seismic data courtesy of Schlumberger Geco-Prakla].

As CO_2 is buoyant (in both gaseous and fluid phases) it will tend to rise to the top of the repository reservoir. Assessment of the depth to the top of the reservoir is therefore a basic prerequisite of CO_2 storage (Figure 20b). It allows a first order estimate of short-term storage capacity, and permits likely migration pathways and extents to be assessed.

Uncertainties in reservoir geometry are significant if the injection is into a reservoir with gentle dips and only minor topography at its top (as at Sleipner), therefore, very detailed depth mapping is required (Figure 20c). This will permit accurate definition of the structure of the top surface to allow the prediction of the overall migration direction and evaluation of the location and volume of any structurally defined traps along the migration paths. This was done using a 3D seismic data around the injection site. Moreover, it requires velocity control from nearby boreholes to effectively minimise uncertainties in depth conversion.

Although significant faulting has not been identified so far in the Sleipner CO_2 repository, in the general case it is important to identify and map any faults in the reservoir and caprock, and to make some assessment of fault sealing capacity (e.g. by empirical fault gouge shale ratio estimation), so as to be able to detect and assess possible reservoir compartmentalization and/or the potential for fault-related leakage.

Knowledge of reservoir properties, such as porosity and permeability, is required to quantify potential storage capacity and likely migration paths and rates. To determine these properties, core material from the reservoir close to the injection was used. Core and cuttings material from additional wells will further improve characterisation, particularly if vertical and lateral reservoir inhomogeneity is suspected. Determinations from material in the likely CO_2 migration pathway, i.e. the top of the reservoir, are of particular importance. Analysis of the reservoir properties was supplemented by mineralogical analysis using XRD (x-ray diffraction) and geophysical logs such as γ-ray and sonic logs. The geophysical log data were used to extrapolate the physical property from the coring point(s) from wells at least as far from the injection point as the predicted CO_2 migration (Figure 21). In regional terms the fairly sparse cover of wells appears sufficient to characterise the reservoir adequately in terms of broad stratigraphy and storage capacity (Table 5).

Assessment of the total reservoir storage potential (Effective Storage Capacity) is desirable, so that a proper injection strategy can be devised. This entails determination of the internal stratigraphy of the reservoir. At Sleipner, the presence of thin shale beds is radically affecting CO_2 distribution in the reservoir, with CO_2 migrating laterally for several hundred metres beneath intra-reservoir shales (see below). It is likely that in the longer term this dissemination of CO_2 throughout the reservoir thickness (rather than just being concentrated at the top) may allow more efficient dissolution of CO_2 and effectively increase the reservoir capacity well above the minimum value defined by the volume of the top reservoir traps. None of these thin shale beds were clearly resolved on the seismic data (not even on the 3D data) and require geophysical well logs for their identification (even utilising log data, the thinner shales are below the thickness resolution limit).

Table 5 Generalised properties of the Utsira Sand from core and cuttings. Mineral percentages based on whole-rock XRD analysis.

Grain size	Porosity	Permeability	Sand/shale ratio	% Mineral					
				Quartz	Calcite	K-feldspar	Albite	Aragonite	Mica and others
Fine (medium)	35-40 % (27-42%)	1-3 Darcy	0.7-1.0 (0.5-1.0)	75	3	13	3	3	3

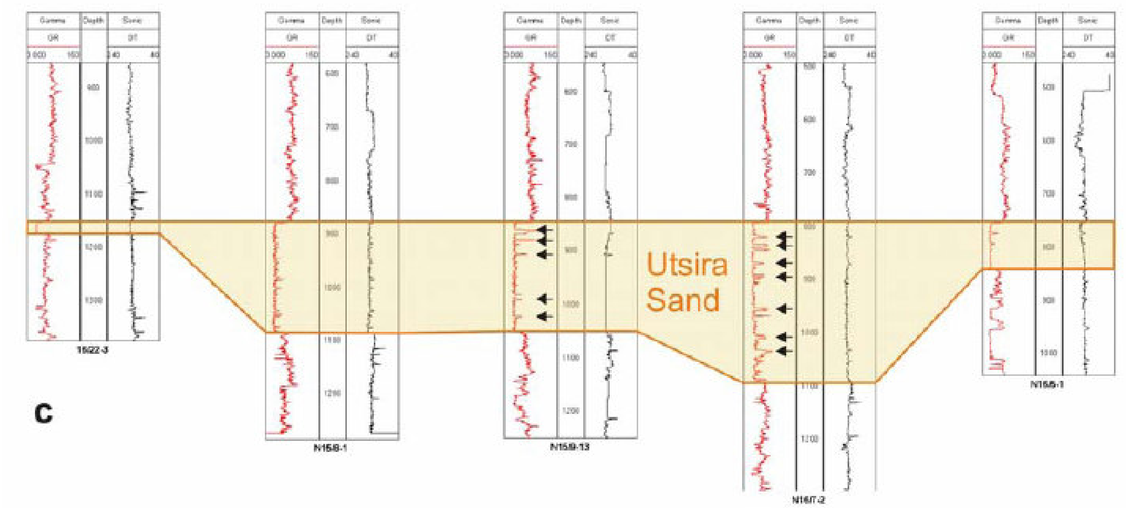

Figure 21 well correlation diagrams from the southern part of the Utsira Sand utilizing γ-ray and sonic logs (total section length about 85 km). Note how γ-ray logs resolve thin intra-reservoir shales (arrowed), and laterally variable sand/shale ratio.

Natural fluid flow in the reservoir is a factor with the potential to affect the migration of CO_2. Fluid flow may be determined from physical measurements of pressure at different locations in the reservoir, or using basin modelling software. In the case of the SACS project, available data indicate that the lateral pressure gradient in the Utsira Sand is very small, perhaps compatible with natural fluid flows in the order of 0.3 to 1 m yr^{-1}. The pressure data are very sparse however (see above) and this figure must be treated with considerable caution. SACS also used basin modelling techniques to calculate theoretical flow velocities based on the compaction history of the Utsira Sand. Velocities of 2 – 4 m yr^{-1} were obtained for the reservoir around Sleipner, though rather conservative (high) permeabilities were assumed. On the other hand, reservoir simulations suggest that hydrodynamic displacement of the CO_2 plume is insignificant, indicative of very low rates of natural fluid flow.

8.3.3 Characterisation of caprocks

Characterisation of caprocks involves knowledge of the extent, nature and sealing capacity of the caprock. It is perhaps the key purely geological element in assessing and establishing the long-term safety case for the CO_2 repository. Determination of the extent of the caprock will rely on a regional spread of boreholes and on the grids of 2D and 3D seismic data. Sample material in the form of core and drill cuttings should be available in sufficient quantity to undertake a detailed suite of analytical tests, which include petrography, SEM, XRD. Due to absence of caprock core material, results from cuttings analysis (e.g. Table 6) are used to assess sealing capacity in a qualitative manner, by comparison with samples from proven oil/gasfield caprocks, or semi-quantitatively such as by the Krushin grain-size method (Krushin, 1997).

Table 6 Generalised properties of Utsira caprocks, based on analysis of cuttings.

sand (>63 µm)	silt (2 - 63 µm)	clay (<2 µm)	% mineral													CEC meq/100g	TOC (%)
			quartz	k-spar	alb	calc	mica	kaol	smect	chlor	pyr	gyp	hal	sylv	bar		
0 - 5%	40 - 60%	45 - 55%	30	5	2	3	30	14	3	1	1	1	2	1	5	6.0 - 20.2	0.68 - 1.28

CEC- Cation exchange capacity TOC- Total organic carbon

At Sleipner the caprock succession is some 700 metres thick and is stratigraphically complex, comprising three main units (Figure 20a). The uppermost unit of Quaternary silts and muds overlies a thick dominantly silty Pliocene succession of prograding clinoforms. The lowermost unit comprises dominantly silty mudstone and seems to be basin-restricted. The ability of the seismic and well data to resolve fine stratigraphical detail around the reservoir/caprock interface has proved essential to predicting potential migration patterns. It is likely that a thin sandy unit (termed the ‘sand-wedge’ by SACS) in the lowermost part of the caprock will provide an important migration conduit; a small dip divergence between this and the top Utsira Sand results in an azimuthal change of some 90^{o} in predicted migration direction (Figure 22). This has important consequences for migration modelling. At Sleipner, there is sufficient structural closure at the top of the Utsira Sand to trap 20 Mt (megatonne) of CO_2 within 12 km of the injection site (Figure 22a).

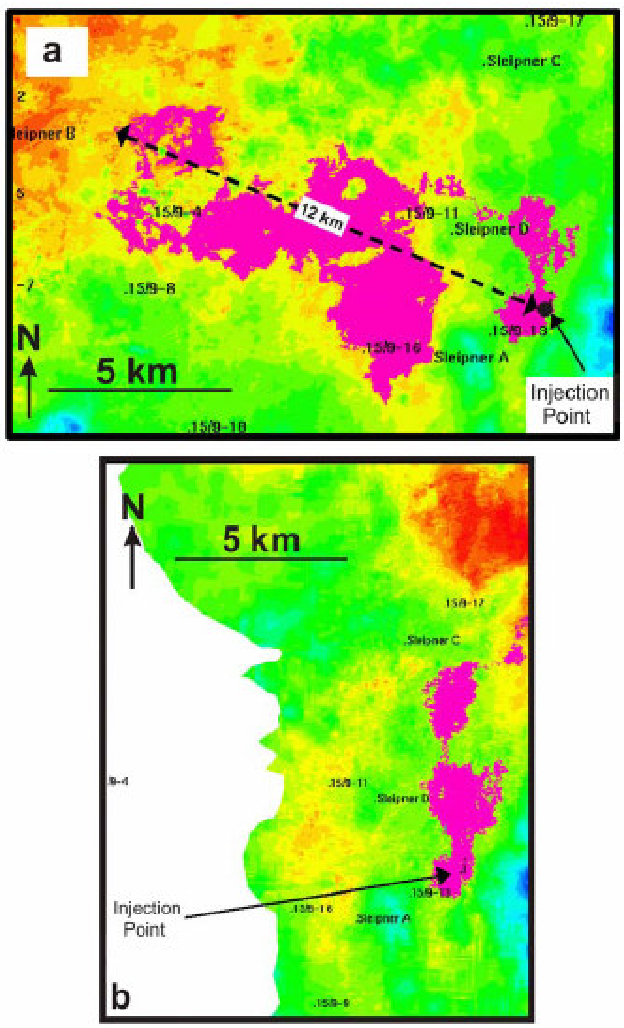

Figure 22 Migration pathways (purple) from the Sleipner injection point. a) Final distribution of 3 x 10^{7}m^{3} (~ 20 MT) of CO_2 assuming migration beneath the top of the Utsira Sand b) Final distribution of 7.4 x 10^{6} (~5 MT) of CO_2 assuming migration beneath the top of the sand-wedge. Note if more than 5 MT of CO_2 it will migrate out of the area of 3D seismic coverage. Two-way time shading ranges from blue (deeper) to red (shallower).

However, if most of the CO_2 migrates beneath the top of the sand-wedge the situation is less well constrained; only 5 Mt of CO_2 are sufficient for the migration stream to leave the area of the 3D survey to the east (Figure 22b). This emphasises the need for very precise depth conversion when dealing with flat-lying repository aquifers.

Injection-induced pressure changes could lead to compromise of the caprock seal and possible geomechanical consequences should be assessed prior to injection commencing. At Sleipner, the required injection pressures are considered most unlikely to induce either dilation of incipient fractures (due to increased pore-pressures) or microseismicity (due either to raised pore pressures or a reduction in normal stress due to buoyancy forces exerted by the CO_2 plume).

8.3.4 *Monitoring the injection process*

Time lapse seismic data - The major success of the SACS project has been the demonstration that conventional, time-lapse, p-wave seismic data can be a successful monitoring tool for CO_2 injected into a saline aquifer (Eiken et al. 2000). Even with the CO_2 in a supercritical, rather than a gaseous, state it has been shown that CO_2 accumulations with a thickness as low as about a metre can be detected - far below the conventional seismic resolution limit of approximately 7 m. Even these thin accumulations cause significant, observable and measurable changes in the seismic signal, both in amplitude and in travel time (Figure 23a).

It is exactly this major effect on the time lapse seismic signal of relatively thin CO_2 accumulations that has built confidence that any major leakage into the overlying caprock succession would have been detected. So far, no changes in the overburden have been observed in the Sleipner, implying that there are no leakages from the Utsira formation.

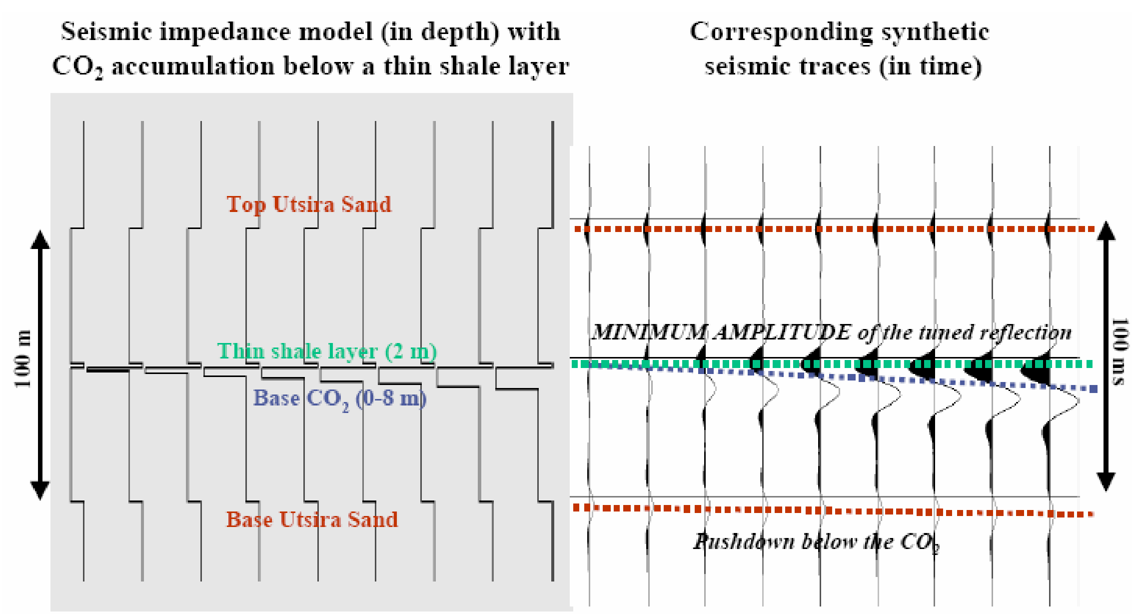

Figure 23a Synthetic model of a 2 m thin shale layer with an increasing CO_2 accumulation (0-8 m) below.

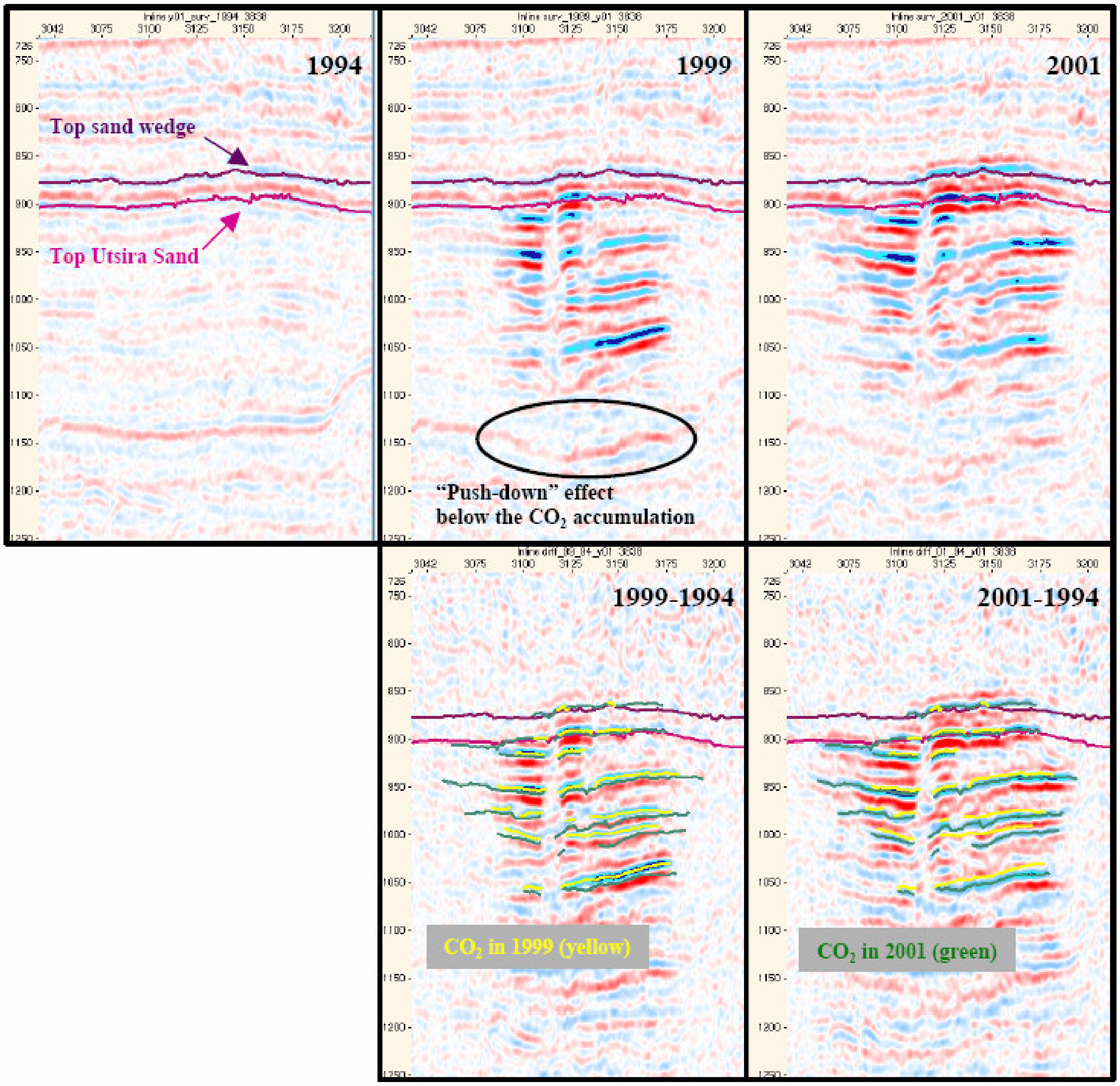

Figure 23b: Inline 3838 through the injection area for the 1994, 1999 and the 2001 surveys including the difference between the 1999-1994 data and the 2001-1994 data. The interpreted CO_2 levels are visualised in yellow (1999) green (2001).

The time lapse seismic data have provided insights into the geometrical distribution of the injected CO_2 at different time steps and show the different migration pathways (Figures 23b and 22c). Due to the lower density of CO_2 with respect to the formation water, buoyancy is the dominant physical process governing the migration. The seismic data have revealed at least temporary barriers (very thin shale layers) to vertical migration of the CO_2 that could not be resolved on the pre-injection baseline data alone. Due to the pronounced effect of the CO_2 on the amplitude of the time lapse seismic signal these barriers have been mapped locally, markedly increasing the understanding of the CO_2 migration within the reservoir. At various

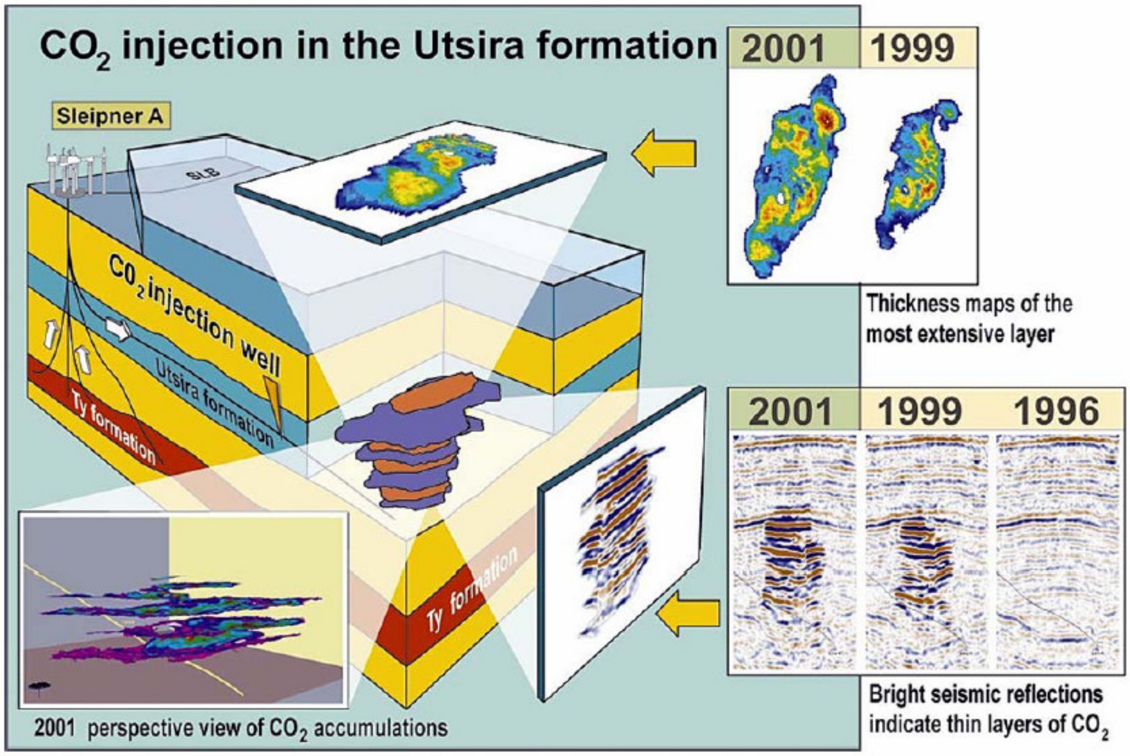

Figure 23c: Repeat seismic surveys and position of injected CO2.

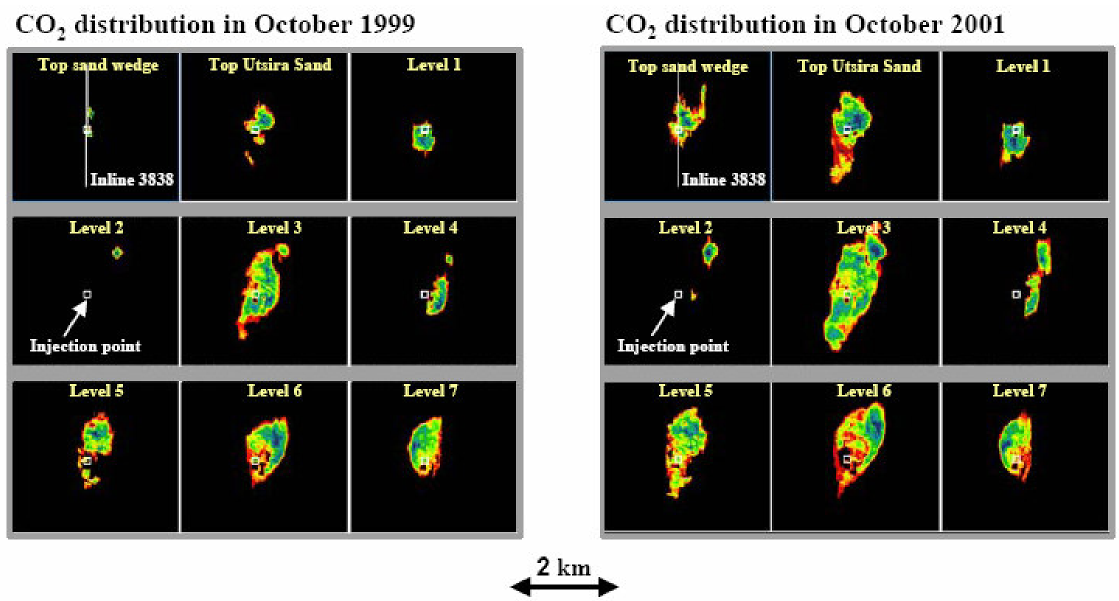

Figure 24: Interpreted CO_2 accumulations at different depth levels (amplitude maps from shallowest to deepest level 7).

locations chimneys have been observed where CO_2 passes through the thin shale layers (Figure 23b). The presence of thin shale layers has radically affected the CO_2 distribution in the reservoir, with CO_2 migrating laterally for several hundred metres beneath the intra-reservoir shales (Fig. 23c). It the longer term, this dissemination of CO_2 throughout the reservoir thickness (rather than just being concentrated at the top) may allow more efficient dissolution of CO_2 and effectively increase the reservoir capacity (Torp and Gale, 2003).

Interpretation of the post-stack seismic data has provided much of the information required to characterise the "CO_2 bubble" including mapping the different CO_2 levels and quantifying the amount of CO_2 at each level (Fig. 24).

Quantitative interpretation of the time lapse seismic data is necessarily linked both to the choice of an appropriate rock physics model, i.e. Gassmann (1951) and also to assumptions on saturation ranges and temperatures. By making these assumptions, a mass balance can be attempted by comparing the actual injected quantity of CO_2 with the seismically derived quantity. Such an analysis has the potential to confirm (as a first order approximation) whether all of the CO_2 is imaged by the time lapse seismic data. A reasonable match between the reservoir simulation model and the seismic data is required to gain insight in the predictive power of the reservoir simulation.

8.3.5 *Integration of time-lapse seismic with reservoir flow model*

Time-lapse data may be compared to results from a reservoir simulator with the aim of improving the flow model. Subsequent predictions of reservoir behaviour will then be more accurate. In the SACS case a particular phenomenon occurred due to the thin shale layers acting as temporary vertical CO_2 migration barriers that could only be identified on the seismic data with CO_2 captured underneath. In other words, assumptions had to be made *a priori* on the shape, the lateral extent and the continuity of these shale layers for the reservoir simulation model. For that reason in SACS a history match has been performed especially honouring the amount of CO_2 at the different depth levels, but only globally (as good as possible) the detailed lateral distribution. Figure 25 shows the synthetic seismics of 2001 created from a realisation of the reservoir simulation model. More information on this topic can be found in Lygren et al., 2002. Other publications are in press.

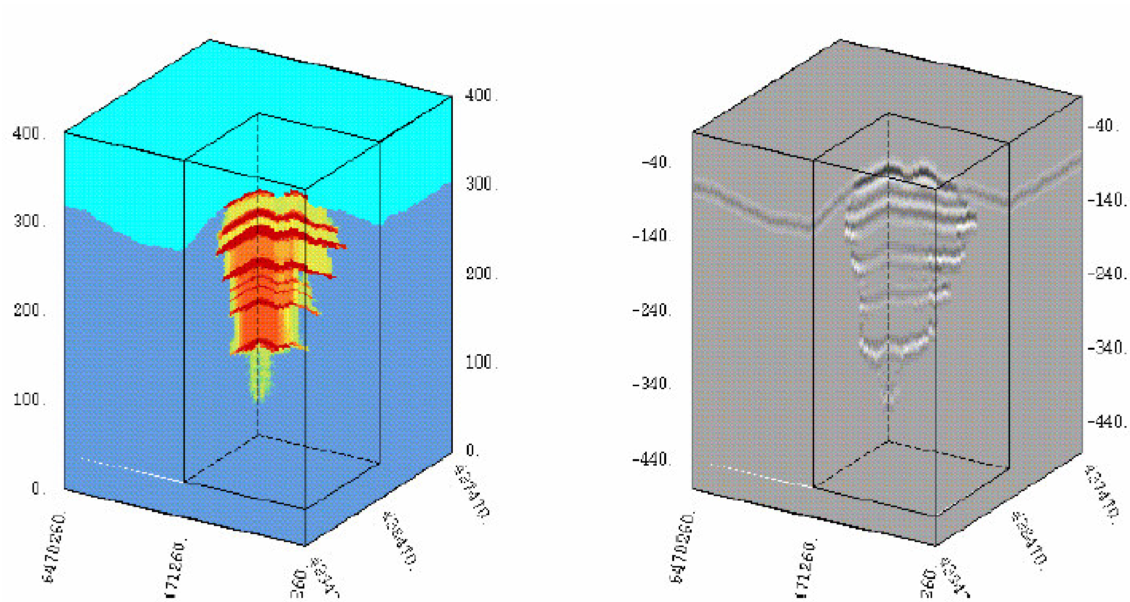

Figure 25: Reservoir simulation model with the corresponding synthetic seismics with depth values in meter (vertical) and local coordinates (bottom).

CO_2 volume estimation from seismic data - In geological CO_2 sequestration projects pre-injection reservoir simulation should be carried out with a reservoir model which is based on the best available geological data. These simulations can predict the CO_2 injection rate that could be maintained, the rise in reservoir pressure caused by the injection, the likely lateral migration of the injected CO_2 and the potential for CO_2 dissolution into the formation water. Pre-injection reservoir simulation was carried out at Sleipner (Korbol and Kaddour, 1995) but this did not form part of the SACS project, which was established after injection began. The pre-injection reservoir simulation indicated injection of CO_2 would be a feasible option from an operational point of view. This was sufficient to allow the project to proceed.

8.3.6 ***Reservoir simulation in SACS: Verifying the seismic and geological interpretations and predicting the long-term fate of CO_2***

Further objectives of reservoir simulation in a CO_2 sequestration project are likely to be:

1. Verify and improve the seismic and geological interpretations of the reservoir around the injection site and re-run simulations of the migration of the injected CO_2 during and shortly after the injection period.
2. Use the history matched reservoir model of the area around the injection site to build a large-scale model to predict the long-term fate of CO_2.

These objectives require history matching and thus should take place during the monitoring of the CO_2 sequestration operation.

In the SACS project, two new reservoir models were built to achieve these latter objectives. The first describes the formation near the injection site. It covers an area of approximately 7 km^2 and consists of a large number of small grid blocks. This model was iteratively calibrated and adjusted in the light of interpretations of the seismic images of the CO_2 accumulations from the repeated seismic surveys performed three and five years after the start of injection. The second model covers an area of 128 km^2 and is being used to predict the migration of CO_2 over a period of several thousand years under the assumption that there is no migration through the upper seal, which is revealed from the current study (Section 7.3.3). This model has to rely on a coarser grid due to computational constraints.

8.3.7 ***Calibration of a local reservoir model by use of repeated 3D seismic***

Reservoir modell - The SACS project graphically illustrates how useful repeated 3D seismic surveys can be to calibrate a local reservoir model. Data from pre-injection seismic, well-logs and petrophysical data obtained from laboratory experiments and core analysis were used to build the original local reservoir model of the Utsira Sand (the reservoir formation) near the injection well. However, because the injection well is a near-horizontal well drilled from the Sleipner A platform it did not provide good 3D data on the nature of the whole thickness of the Utsira Sand reservoir at the injection point. Furthermore there are no other wells in the immediate vicinity of the injection site. The majority of the data used to construct the model was obtained from wells which passed through the Utsira Sand beneath, or very close to, the Sleipner A platform, some 3 km from the injection site. At the injection site the Utsira Sand was interpreted to consist of a highly permeable sand body more than 200 m thick intersected by thin horizontal discontinuous shale layers.

CO_2 is injected close to the bottom of the formation. The shale layers are interpreted to impede its vertical migration and cause the entrapment of the CO_2 in large, near-horizontal 'bubbles' within the porous medium of the sand. The barrier layers are either semi-permeable, or have localized spill areas that allow migration of CO_2 to the consecutive barrier layers above. The discontinuity and heterogeneity of these shale layers are thought to cause the CO_2 to be transported in distinct chimney-like columns that are imaged on the repeat seismic surveys.

Only the two upper shale horizons could be mapped from pre-injection seismic *i.e.* the cap seal of the formation and a shale approximately 15 m below the cap (the sand between these two shales is commonly referred to within the SACS project as the 'Sand Wedge'). The other shales were too thin to be mapped from the seismic and were located from the 1999 time-lapse seismic data where the major seismic reflectors were interpreted as CO_2 bubbles being retained by the shales. The shale layers were represented in the model by transmissibility modifiers attributed to layers that correspond to those detected by the seismic survey.

Reservoir simulation incorporates the predominant driving mechanisms that control the migration of CO_2. The model is calibrated by modifying various parameters to achieve history matching and the history-matched model is ultimately adopted to make future predictions. The transmissibility of each shale and the chimney-creating conduits were obtained by adjusting the transmissibility multipliers so that the resulting accumulations under the layers became similar in size to the corresponding seismic reflector. This is an iterative process that is still continuing.

Thus the SACS local reservoir model has demonstrated that if a well does not exist at, or very close to, the injection site, as at Sleipner, the initial calibration of the physical conditions and reservoir model may not be ideal. However, if good quality 4D seismic data is available, the reservoir simulation can still be history matched to the seismic interpretation.

Fluid and transport properties - Given a hydrostatic pressure gradient, in a thick reservoir such as the Utsira Sand the temperature gradient is the most important parameter that has to be taken into account if fluid properties are to be modelled correctly. Thus it was recommended that careful temperature and pressure measurements are made in the reservoir in future CO_2-injection projects. The CO_2 density in particular will be erroneous if these gradients are not correctly accounted for.

In the Utsira Sand, the temperature is thought to vary from about 29°C to 37°C from the top of the formation about 800 m below mean sea level to the injection point at 1040 m depth. The pressure increases downwards through the formation and temperature and pressure have opposite effects on the density, so in practice the density is relatively constant down through the reservoir, at about 700 kg/m^3 corresponding to a CO_2 viscosity of about 0.06 mPa s.

Free CO_2 in both liquid or gas phase will give strong reflections on seismic because of the strong contrast in velocity of sound between CO_2 and brine. CO_2 dissolved in brine will, however, not be visible on seismic because CO_2 saturated brine will have approximately the same velocity of sound as under-saturated brine.

The solubility of CO_2 in brine at the Utsira conditions is approximately 53 kg/m^3. Dissolved CO_2 could therefore potentially be a significant contribution to CO_2 storage in this aquifer, *e.g.* all of the CO_2 injected in this project ($1.7 \cdot 10^6$ Sm^3/d) for 25 years would dissolve in a brine "cylindrical" pore volume 1300 m in radius and 200 m tall. In the CO_2 plume above the injection point some water will be contacted by CO_2 during migration up through the formation. The shales will spread the CO_2 over a large area. This will increase the surface of the CO_2 phase and increase dissolution. In practice, however, the amount CO_2 dissolved during the injection period will be limited because only a small fraction of the brine will be contacted by CO_2. Although the geophysical interpretation of the seismic is non-unique, iteration between the geophysical interpretation of the seismic reflections attributed to the injected CO_2 and the reservoir simulations showed that good matches between observed and simulated bubble areas could be achieved even if CO_2 solubility was completely neglected. From this it can also be concluded that the shale layers do not disperse large amounts of CO_2 into small leak streams when it is transported from layer to layer. The CO_2 transport must rather be concentrated at localised spill points, curtains, or holes.

*8.3.8 **Simulation of the long-term fate of CO_2 in a large-scale model***

One of the main objectives of reservoir simulation in a geological CO_2 sequestration project is to make long term predictions of the fate of the injected CO_2. The reservoir model constructed for this purpose should include the major features of the local model that control transport of CO_2 on the relevant time scale. The fluid model of CO_2 and brine must feature correct volumetric data (densities), phase behaviour (solubility) and transport properties (viscosities and diffusion coefficient).

In the SACS project, the information from the calibrated local model was extrapolated to build a 3D reservoir model covering an area of 128 km^2 to predict the fate of CO_2 over a time period of thousands of years.

Capillary pressure and relative permeability describing the interaction between the porous media and the fluids were measured in laboratory experiments on Utsira cores. Computational constraints limited the number of grid blocks in the model to less than one million to achieve acceptable computation times. This represents a substantial coarsening of the grid compared to the local model. Preserving the physical consistency of the major transport phenomena in the new grid is a major challenge. In the model the cap rock shales are assumed to provide a capillary seal for the CO_2 phase preventing upward migration, but allowing molecular diffusion of CO_2 through the overlying strata.

The results of the simulations show that most of the CO_2 accumulates in one bubble under the cap seal of the formation a few years after the injection is turned off. The CO_2 bubble spreads laterally on top of the brine column and the migration is controlled by the topography of the cap seal only.

Molecular diffusion is driven by concentration gradients and can usually be neglected in reservoir simulations as it is a slow process compared to other transport processes. It is attenuated due to diminishing concentration gradients, which is a result of the diffusion process itself. In this case, however, diffusion of CO_2 from the gas cap into the underlying brine column will have a most pronounced effect. The brine on top of the column, which becomes enriched in CO_2, is denser than the brine below due to the special volumetric properties of the CO_2-brine system. This creates an instability that sets up convectional currents maintaining a large concentration gradient near the CO_2/brine interface, enhancing the dissolution of CO_2. This is illustrated in Figure 26.

Maps of the bubble as function of time are shown in Figure 27, where the top of the sand wedge is the controlling seal. In these simulations the dissolution of CO_2 is neglected. If dissolution is included the bubble will reach a maximum size after probably less than 300 years. After this time dissolution is the dominating effect on bubble extension and the bubble will gradually shrink and finally disappear after less than 4000 years. This process commonly is called solubility trapping (Section 3.2.3). The primary benefit of solubility trapping is that once CO_2 is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upwards. Next, it will form ionic species as the rock dissolves, accompanied by a rise in the pH. Finally, some fraction may be converted to stable carbonate minerals (mineral trapping), the most permanent and secure form of geological storage (Gunter *et al.*, 1993). Thus preliminary results suggest that in the long term (> 50 years) the phase behaviour (solubility and density dependence of composition) will become the controlling fluid parameters at Sleipner.

An alternative scenario where Top Utsira Sand (i.e. the top of the sand below the Sand Wedge) is the controlling topography for migration was also simulated. Figure 28 show that the CO_2 will follow a more eastern path. This illustrates how sensitive the migration is to small changes in topography. Top Utsira and the top of the sand wedge are only between 14 and 35 m apart and relatively parallel. The top of the sand wedge dips slightly more towards the south west though, resulting in the large differences between distribution patterns. This test is only presented to illustrate the sensitivity of topography because it is quite unlikely that Top Utsira will retain any CO_2 on long term because of its permeability.

Upward molecular diffusion of CO_2 through the water-saturated overlying shales can potentially represent an escape path for CO_2 into the atmosphere. Along this pathway injected CO_2 will not reach the sea floor until several hundred thousand years after the end of injection. This escape mechanism can in practice be neglected.

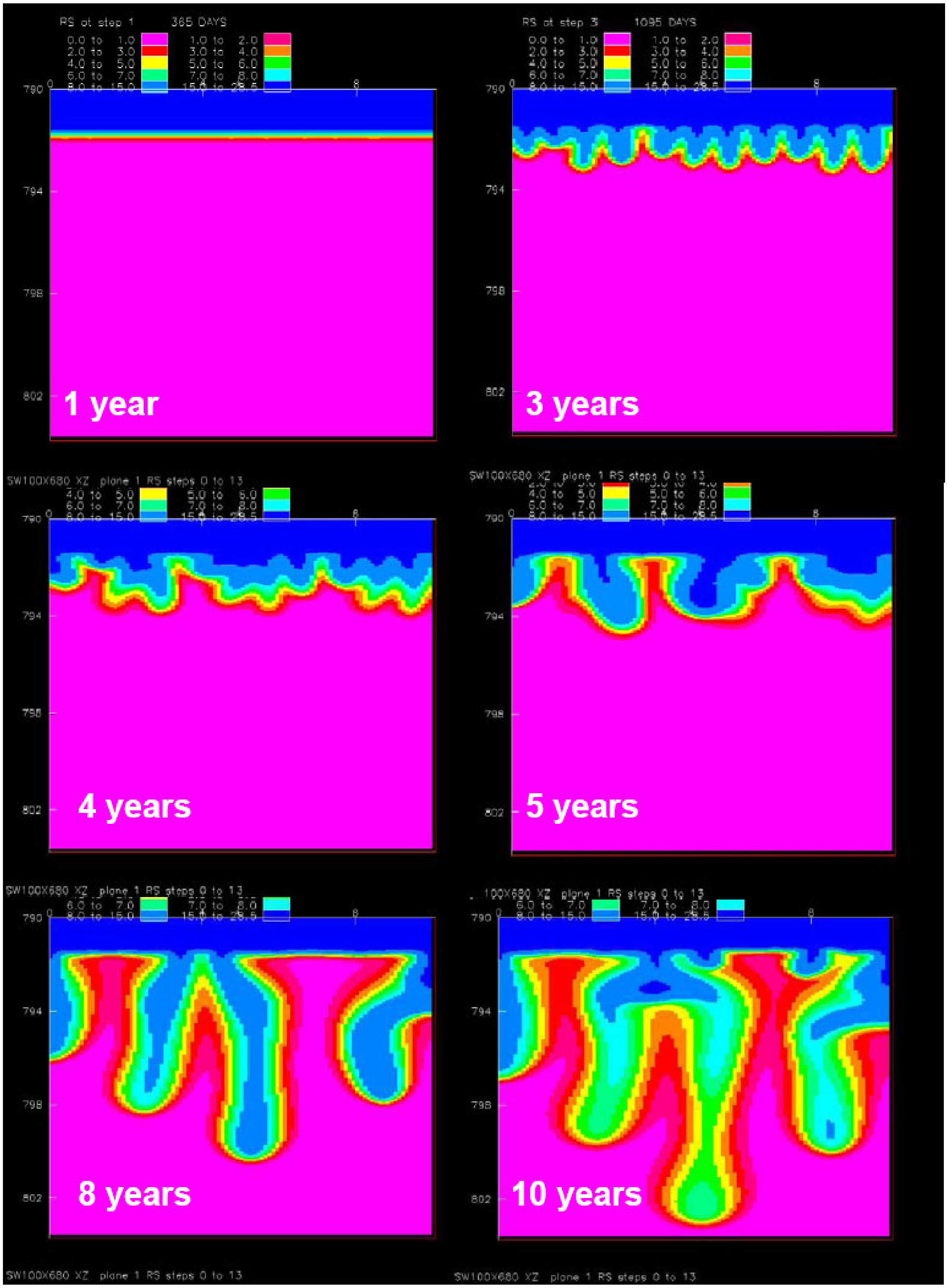

Figure 26. Concentration profiles in a 10 x 13.6 m segment just below the CO_2 brine contact. From a meta-stable diffusion front (upper left) convectional plumes gradually develop. This convection gives a significant contribution to the dissolution.

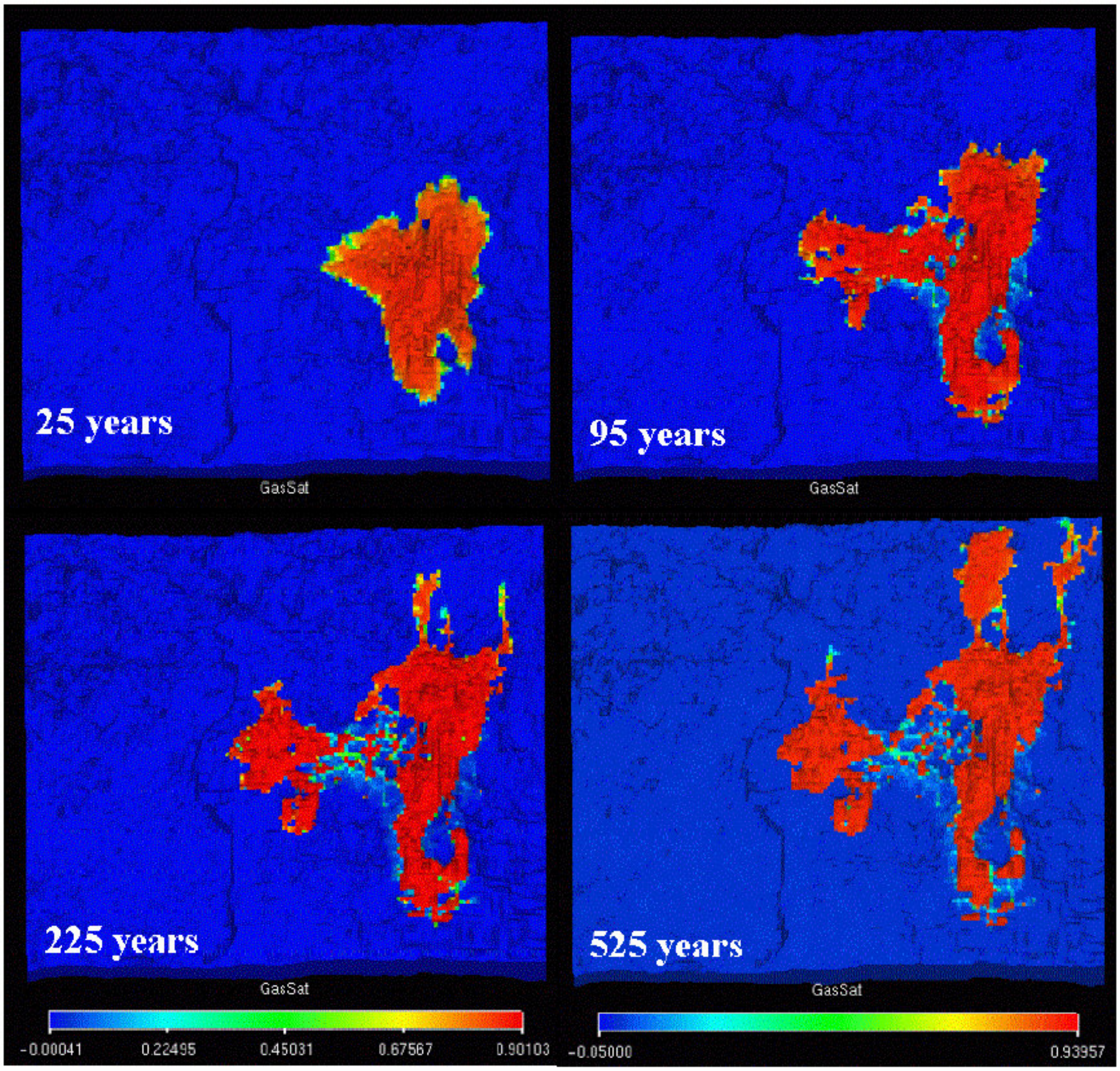

Figure 27: Maps of the CO_2 bubble migrating under the top of the sand wedge as function of time. CO_2 dissolution has been neglected. After 500 years CO_2 reaches the boundaries of the model and starts to migrate out of the model.

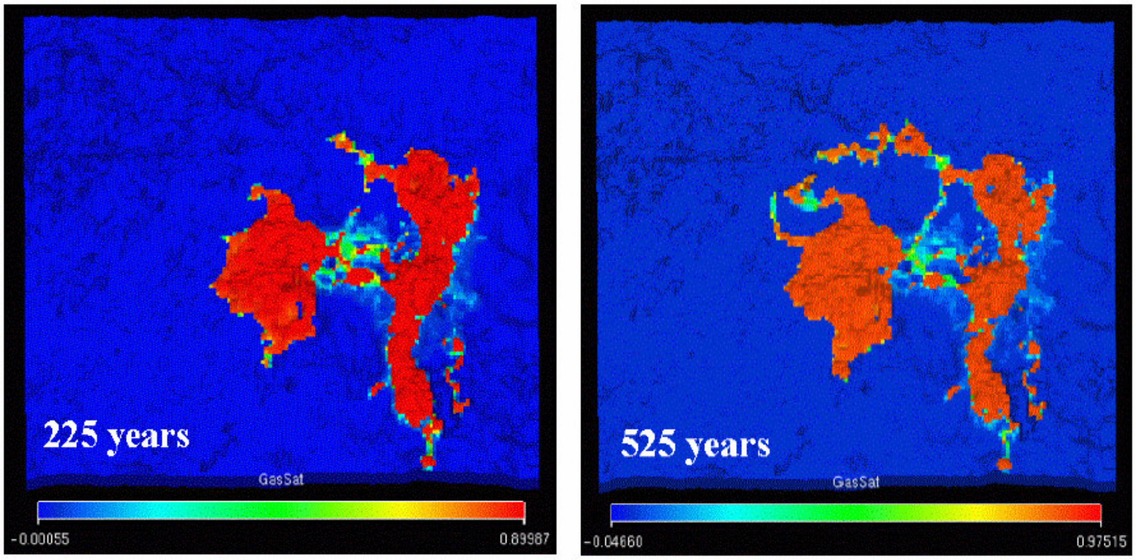

Figure 28: Maps of the CO_2 bubble migrating under the Top Utsira as function of time. CO_2 dissolution has been neglected. In this case the CO_2 follows a much more eastern path than in the case were the top of the sand wedge was controlling the migration.

8.3.9 *Assessing the geochemical effects of CO_2 injection*

It is essential to have a good understanding of the fluid chemistry and mineralogical composition of any potential reservoir and caprock so as to elucidate their reactivity with CO_2. Depending on the nature and scale of the chemical reactions, the reservoir-CO_2 interactions may have significant consequences for the CO_2 storage capacity, the injection process, and long-term safety, stability and environmental aspects of CO_2 storage (Czernichowski-Lauriol et al., 1996a, b).

At the start of the SACS study only limited geochemical information and samples were available from the Utsira Sand. This included:

- A single (partial) analysis of Utsira formation water from the Oseberg field approximately 200 km north of Sleipner.
- A 7 m core of Utsira Sand from the Sleipner field (of which 1 m sections of frozen core were supplied to the geochemists).

The core sample allowed for detailed mineralogical analyses and determination of transport properties. However, the core sample was heavily contaminated by drilling fluids, and no useable formation water sample could be obtained from it. Only one borehole terminates in the Utsira at Sleipner (the CO_2 injection borehole), and unfortunately no produced porewater samples were available from it.

Although there is a single analysis of Utsira porewater from the Oseberg field, it is limited by the lack of analyses of Al and Si. For predictive modelling, it was therefore necessary to assume that these elements were controlled by saturation with respect to specific minerals – in this case kaolinite and chalcedony. However, during the study, a surface sample of formation water from the Brage field (also about 200 km north of Sleipner) was obtained (but without information on the gas phase) and analysed for a range of elements (including Al and Si). However, the sample was unpreserved (unfiltered and un-acidified) and the Al and Si analyses look problematic.

Despite this lack of information and samples, a reasonable assessment of baseline conditions within the Utsira sand was made by combining information from the Sleipner, Oseberg and Brage hydrocarbon fields, and through numerical modelling and 'blank' experiments. These laboratory experimental investigations were also designed to provide information on in-situ porewater chemistry, as mentioned later.

Knowledge of the chemical makeup of the reservoir seal and its transport properties is required to quantify possible chemical reactions and their rates, together with overall sealing efficiency. To determine these properties, a minimum prerequisite is to have core material from the caprock above the injection point. Samples of borehole cement should also be available for testing and analysis.

During the SACS study no caprock core material was available for study. It was therefore not possible to study its bulk properties and porewater chemistry. However, some drill cuttings were located, and cleaned off drilling fluids. These cuttings were suitable for a limited range of mineralogical analytical techniques (petrography, SEM, XRD). Results from these tests were used to assess sealing capacity through comparison with samples from proven oil/gas field caprocks. The Krushin grain-size method was also used. The interactions of CO_2 with borehole cement were not addressed in this study. A key aspect of any future investigations at Sleipner would be to obtain caprock core material and samples of borehole cement. The properties of these, and their interactions with CO_2, could then be investigated in detail.

8.3.10 ***Determination of the geochemical impact of injected CO_2***

The impact of injected CO_2 can only really be assessed once there is a sufficiently good understanding of the baseline conditions. Once these have been defined, then changes from them can be more readily identified. There are a variety of approaches that can be used. They combine numerical modelling and observations from laboratory experiments, field monitoring, and natural analogues.

Observations from laboratory experiments - During the SACS project both static and dynamic experiments were assembled. A number of identical static (batch) experiments were undertaken. These simple and relatively low cost experiments used fixed amounts of Utsira Sand and synthetic Utsira porewater, plus fixed temperature and pressure of CO_2. Individual experiments were terminated after different timescales. Detailed analysis of the reaction products provided 'snapshots' of reaction progress over a 2 year period. The above experiments were compared to similar experiments pressurised with nitrogen. These latter 'blank' experiments were also useful to simulate conditions prior to CO_2 injection, and hence helped to fix baseline conditions. Dynamic (flowing) experiments were conducted to investigate how geochemical reactions impacted upon fluid flow and vice-versa. Standard 'core flood' equipment was used for several of the tests. However, also used were non-metalic (PEEK) tubes that were joined to create a column of Utsira sand 2.4 m long.

The experiments on the Utsira sand have revealed changes in fluid chemistry, associated mainly with dissolution of primary minerals. The experiments pressurised by CO_2 led to large and rapid increases in concentrations of Group II metals (and in particular Ca, Sr and Fe), as well as slow and slight increases in silica concentrations. This suggested fast partial dissolution of carbonate phases, while dissolution of silicate or aluminosilicate minerals was a much slower but real process. However, direct evidence from mineralogical observations has never been possible despite the high water-rock ratio used for these experiments (10:1), their relatively long duration (up to 2 years) and the higher temperature (70°C) used for some of them. This is because the reactivity of the Utsira sand was low and changes were below the resolution of the analytical technique or below the natural mineralogical variation within the sand.

Observations from field monitoring - The most obvious way to obtain direct geochemical information would be by direct sampling of a CO_2 injection site. Once baseline conditions are established, longer-term monitoring of the injection process would be required. Access to samples over a range of timescales would be important. This approach would require observation boreholes with repeat fluid sampling to monitor fluid chemical changes. Sidewall coring, or the drilling of boreholes through the CO_2 'bubble' could be necessary to obtain samples of rock that had been in contact with CO_2 for a variety of timescales. Such an approach would be useful in providing highly relevant 'real time' information about a large-scale system.

During the SACS project, the lack of observation boreholes and related samples made it impossible to monitor directly the geochemical processes occurring within the Utsira at Sleipner. However such an approach is being used in another industrial CO_2 sequestration project - the Weyburn oil field in Canada[4].

Observations from natural analogues - This approach utilises relevant information from other sources than the selected site to generate a better understanding of the CO_2 injection system. Natural accumulations of CO_2 exist in many parts of the world and have many analogous features to any CO_2 injection operation, although these may not be exactly comparable. As such, these 'natural analogues' can provide much useful information, especially about long-term processes as the CO_2 can, in many cases, be proved to have been trapped for thousands or millions of years. Study of natural accumulations of CO_2 has the advantage of similar physical size and timescale of reaction. This can build confidence in models that predict likely responses of reservoirs to geological sequestration. However, costly studies including the drilling of boreholes are needed to gain a reasonable understanding of the analogues. Several research projects on natural CO_2 accumulations are presently underway in the world, such as the European NASCENT project[5], the American NASC project (Stevens et al., 2001) and the Australian GEODISC project[6]. One of the objectives of these projects is to study the geochemical effects of CO_2 on reservoir rocks and caprocks, for various geological contexts. Although only analogous to any sequestration system, natural accumulations of CO_2 also have the advantage that they are a good way to demonstrate that certain rocks can safely contain CO_2 for geological timescales.

Numerical modelling - Computer simulations are very useful way to rapidly scope a range of different scenarios. They can predict the effects of CO_2 addition to formation porewaters, and the consequent changes in fluid chemistry and reservoir mineralogy.

Within the SACS study, numerical modelling was used to interpret, and hence to better understand the laboratory experiments, based on thermodynamic, kinetic, flow and transport processes. Batch experiments were modelled using geochemical models while coreflood experiments were modelled using coupled reactive-transport models. At this stage, 1D simulation was sufficient to describe the coreflood experiments. The codes used were EQ3/6 (Wolery, 1995); DIAPHORE (Le Gallo et al., 1998), MARTHE (Thiéry, 1990) and Specific Chemical Simulators (Kervévan and Baranger, 1998; Kervévan et al., 1998) constructed using the ALLAN/NEPTUNIX code generator package (Fabriol and Czernichowski-Lauriol, 1992). For most of the major elements, the predicted trends were in reasonable agreement with the experimental observations on the Utsira sand. However sensitivity calculations were necessary to fit at best the experimental results. This proves that experiments are essential to assess the key site-specific processes relevant to the natural system being studied.

Within the SACS project, the objective of the geochemical investigations was to assess the potential for geochemical reactions between injected CO_2, formation water and the Utsira sand, based on direct observations from laboratory experiments under simulated reservoir conditions for timescales up to 24 months.

Unfortunately, only limited geochemical baseline data were available within the SACS project. This necessitated the use of certain (logical) assumptions in the design of the experimental programme and in the modelling work. In general, the Utsira sand showed only limited reaction with CO_2. Most reaction occurred with carbonate phases (shell fragments), but these were a very minor proportion (about 3%) of the overall solid material. Silicate minerals showed only slow and minor reaction. Then, in terms of geochemical reactions, the Utsira sand would appear to be a good reservoir for storing CO_2. However further studies are needed to assess the long term storage behaviour within the Utsira formation. In particular, numerical modelling at reservoir scale should be carried out, such as initiated by Johnson et al. (2001). This implies feedback between reservoir simulations and geochemical modelling. Another key area that still remains highly uncertain is the behaviour of CO_2 with the reservoir seal (both caprock and borehole cement seals). Analysis of borehole core material from the caprock at Sleipner is the only way to provide sufficiently detailed information on caprock mineralogy and porewater chemistry. Acquisition of such material should be a priority.

[4] (http://www.ieagreen.org.uk/weyburn.htm)
[5] (http://www.bgs.ac.uk/nascent)
[6] (http://www.apcrc.com.au/Latest%20Releases/geodisc.htm)

8.3.11 *Assessment of monitoring techniques*

Multi-component (MC) seismic monitoring Multi-component (MC) sensors can be used to record shear (S) waves as well as compressional (P) waves. On land, three polarised shear-wave sources, together with 3-component geophones, can be used to produce 9-component (full-wave) data. Offshore, 4C sea-bottom instruments (3 component geophones plus a hydrophone), utilise P to S mode conversions to record PS (P-downgoing, S-upgoing) datasets. MC datasets contain inherently more information than conventional data. Firstly, S-waves propagate exclusively through the rock matrix and are relatively unaffected (other than by pressure) by the nature of the pore fluid. This allows S-waves to image through volumes containing anomalous fluids (e.g. CO_2 bubbles), more effectively than P-waves, and makes S-wave acoustic properties more uniquely diagnostic of lithology. Secondly, S-waves interrogate azimuthal subsurface properties, so the polarized waveform may exhibit birefringence due to velocity anisotropy. This among others can be used to measure azimuthal anisotropy in rock properties (due to structural fabric, or fractures) or lateral variations in effective stress (fluid pressure). Additional benefits that MC data can produce are summarized in (Liu et al. 2001).

Assessment of gravity surveying as a monitoring tool - Monitoring the injected CO_2 by repeated high-precision gravity measurements (micro-gravity) can provide better constraints on *in situ* CO_2 density (Williamson et al., 2001). As seismic waves are fairly insensitive to density, gravity data can provide information which is complementary to that given by seismic methods. Such monitoring might be of particular use in mass and volume calculations. Thus if large quantities of CO_2 dissolve in the formation water, this may be detected by gravity. Alternatively, if significant amounts of gas are breaching through the cap rock, gravity monitoring may serve as a “catastrophic early warning system”. The lateral resolution is much lower than for seismic monitoring, but for quantification and further dynamic modelling, it could, together with the seismic geometrical information, be a valuable additional monitoring tool, provided density contrasts are large enough. [In the Sleipner case with CO_2 injected into the Utsira Sand, a detectable gravity change is expected to arise if CO_2 densities are low (high geothermal gradient scenario)]. If such a monitoring project is undertaken, pre-injection baseline data are of great value and their acquisition is strongly recommended.

At Sleipner, baseline gravity data were not collected, but the project is still considering the method for future monitoring. Offshore the only way to obtain sufficient accuracy is by seafloor measurements.

Microseismic monitoring - In general, the principal advantage of using microseismic monitoring is its continuous nature. In other words, if a cause and effect link can be established between the appearance of microseismicity and the increase in pore pressure in the reservoir due to the flow of CO_2, then, theoretically, a real-time picture is provided of the passage of CO_2 at certain specific points. It is also possible to characterize zones of weakness in the reservoir (or its caprock), where pre-existing fractures or joints move in brittle shear and therefore constitute preferential flow paths.

From a practical point of view, microseismicity appears mainly in low-porosity carbonate rocks and when injection pressures are relatively high (several tens of MPa). Given the porosity values at Sleipner, microseismicity is unlikely to appear in the Utsira Sand except perhaps in shale lenses or in the overlying shale caprock (Fabriol, 2001). This latter case could be the most interesting to monitor as it would reveal the presence of leakage in the caprock. However, it remains to be proven that microseismicity actually does exist in the Sleipner case.

Though microseismic monitoring is not considered to be of great use at Sleipner, it is expected to be more appropriate to other CO_2 underground storage projects, particularly in low permeability reservoirs.

Petroacoustics and thermodynamics related to seismic monitoring - The quantitative interpretation of time-lapse seismic monitoring relies on a sufficiently accurate estimation of the fluid substitution impact on seismic velocity in the reservoir. The theoretical basis of this quantification is the well-known Gassmann (1951) model. In the SACS-case shear wave information through a DSI-log has proven very valuable for the Gassmann modelling and AVO (i.e., variation with incidence angle) analysis.

Within SACS a reliable method has been developed for the laboratory verification of Gassmann's formula and parameters by measurement on consolidated samples (Zinszner, 2002). The method is based on the substitution of fluids of various compressibilities. To preserve the properties of the clay fraction in the sandstone diphasic saturation states have been used. The room dry sample is first saturated with brine. The brine is displaced by viscous oil (non-miscible viscous displacement), and then the viscous oil is displaced by hydrocarbon liquids of varying bulk modulus (e.g. kerosene, hexane, pentane, etc). The P and S wave velocity measurements are performed under pore and confining pressure (up to 70 MPa).

This method is very successful when performed on normally consolidated samples, but the experimental difficulties in applying this method to loose sandstone are expected to be large. Similar difficulties are encountered for any petrophysical measurement; permeability, capillary pressure etc, but they are more pronounced for petroacoustics (a careful preservation of the initial rock microstructure is needed). In the Utsira formation where the sand/sandstone is unconsolidated, this is not verified yet.

In order to provide the CO_2 - methane mixture compressibility (isothermal, isentropic) and density for temperatures and pressures in the range encountered in the reservoir, the SBWR (1995) equation has been applied (a modification by Soave of the 1940 Benedict-Webb-Rubin equation). At the beginning of the SACS study, it was supposed that the methane concentration could be several percent (relative inefficiency of washing process). Actually the methane content appears lower than 1%. The density/ compressibility values for a wide range of P, T conditions and for mixtures with CO_2 concentration greater than 95% molar, corresponding to the SACS conditions, have been determined. CO_2 concentrations less than 95% molar are far from the Sleipner conditions and would require new computations.

8.4 Summary of recent studies

Several studies were carried out at the Sliepner since 2004. Here a summary of the most important works is presented briefly. Gaus *et al.* 2006 studied the impact of CO_2 storage on the Utsira reservoir and its cap rock at Sliepner using a long term coupled transport and geochemical modelling. This is a key to understanding the long term geochemical impact of CO_2 storage. Using three different models (GEM-GHG, PHREEQC and TOUGHREACT) both the geochemical interactions as well as their impact on host rock porosity was assessed for the Nordland Shale cap rock and the Utsira reservoir over thousands of years. Results on impact of dissolved CO_2 on the cap rock after 3000 years at Sleipner shows that depending on the reactivity of the cap rock, vertical diffusion of CO_2 can be retarded as a consequence of geochemical interactions. The calculated porosity change is small and is limited to the lower few metres of the cap rock. A slight decrease in porosity is predicted due to alteration of plagioclase and is entirely dependent on the exact chemical composition of the solid solution (with pure albite and anorthite as end-members). This slow process might slightly improve the cap rock sealing capacity. Moreover, at the cap rock/reservoir interface minor carbonate dissolution is expected to occur. After a 10 000 year simulation Gaus *et al.* 2006 concluded that:

- CO_2 is completely dissolved and it is possible to assess its long term fate at this stage: for 100 moles injected, approximately 70 ends up dissolved in the formation water, 30 are released as a consequence of carbonate dissolution, and 60 ends up in ionic bicarbonate form;
- main mineralogical changes take place where the dense temporary CO_2 bubble was present and there most of the carbonates dissolve;

Overall results indicate that in the Utsira case geochemical reactions, other than dissolution of CO_2 and pH change, are unlikely to play a major role due to its low reservoir temperature (37°C) leading to very slow reaction kinetics and its little reactive mineralogy. Besides the reactivity in the cap rock induced by diffusing CO_2 is expected to be minor in general, and was positive with respect to the sealing efficiency in this study.

The integrity of the caprock is very important with regard to CO_2 storage in underground operations. Caprock properties of the Nordland Shale recovered from the 15/9-A11 well, was assessed for integrity at the Sleipner area (Springe and Lindgren, 2006). In the study reservoir condition experiments on fresh caprock samples were carried out with the aim to determine capillary entry/break-through pressure and *in-situ* porosity-permeability properties of the Nordland Shale caprock. They found out that the Lower Seal of the Nordland Shale succession has a thickness of 50-100 m and is the primary seal to the Utsira Sand at a depth of approximately 800 m near Sleipner. The *in situ* porosity is 34-36% and permeability 750-1500 nD it can be classified as a shallow seated caprock with properties very different from what is observed for typical petroleum caprocks that have been buried much deeper. Such caprocks often have porosities below 20% and permeability below 10 nD (Dewhurst *et al.*, 1999).

Capillary entry pressure was 3-3.5 MPa to N_2 and CO_2 gas and 1.7 MPa to supercritical CO_2 ($scCO_2$); thus the entry pressure seems to be solely related to the interfacial tension properties of the subject fluids. There was no significant difference between entry pressure and break-through pressure; in all experiments where this could be tested break-through occurred after a while with no additional pressure increase relative to the entry pressure (Springe and Lindgren, 2006). Reservoir pore pressure in the Utsira Sand vary within 8-11 MPa from top to bottom; in this pressure regime scCO_2 density is 500-700 kg/m^3. With a formation water density of 1013 kg/m^3 a density contrast of ~ 400 kg/m^3 would seem reasonable, which means that the caprock would hold a scCO_2 column of ~ 400 m. With a maximum thickness of ca. 300 m of the Utsira Sand and much less for the scCO_2 bubble spreading beneath the seal it seems unlikely that scCO_2 will enter the Nordland Shale (in other words the Nordland Shale has high seal capacity). However, this conclusion may change if regional variation in grain size exceeds the range observed in the 15/9-A11 well.

During and after the injection of carbon dioxide (CO_2), some of the CO_2 can dissolve in the formation water, some can react with the present minerals and some of the CO_2 can exists as a separate phase (immiscible). Mobility of immiscible CO_2 is of major importance for evaluating the risk of leakage. Khattri *et al.*, 2006 studied the impact of regional water flow on the distribution of immiscible CO_2 using numerical modelling of reactive transport at the Utsira formation. They used input data for the simulations similar to the CO_2 storage facility at the Sleipner Vest field in the Norwegian sector of the North Sea. For example, injection rate, geometry, injection period and medium properties.

A regional flow of 1 m/y of the formation water considered during the simulations. Immiscible CO_2 is mobilized due to buoyancy forces, and by the movement of the formation water. Spatial evolution of the CO_2 immiscible phase at times 1 year, 10 years, 20 years, 100 years, 170 years, 200 years, 400 years, 500 years and 1000 years were simulated (Figure 29). The range of CO_2 immiscible saturation is 0.01 to 1.0. It is interesting to note in the Figure 29c that within 20 years CO_2 reaches the boundary. Immiscible CO_2 get carried away by the regional water flow. The authors used a regional water flow rate of 1 meter per year. This value may not be a very good estimate of the natural fluid flow at the Utsira formation (Holloway *at al.*, 2002). Numerical simulation has calculated fluid velocities in the order of 2 to 4 meters per year (Torp and Gale, 2004). Roughly speaking a regional flow of 4 meters per year can push immiscible CO_2 to the boundary of a 3000x3000x200 m^3 domain within a period of 5 years. Regional flow can thus dramatically affect the CO_2 distribution. This hints further that pressure build up as a consequence of CO_2 injection is unlikely to occur.

Monitoring is essential for many purposes. It can be used to quantify the amount (mass) of *in situ* CO_2, thereby testing the monitoring techniques, and possibly the storage process in the reservoir. One of the largest sources of uncertainty in estimates of CO_2 mass comes from uncertainty in the density of CO_2 within the Utsira formation (Nooner *et al.*, 2006). The density of CO_2 depends primarily on the temperature. Until recently, most of the work that has been done in reservoir simulations and in estimating the *in situ* CO_2 mass has assumed that the 37 °C measurement is correct, and that the CO_2 density is 650-700 kg/m^3 (Nooner *et al.*, 2006). Therefore, determining the *in situ* CO_2 density is important for the long-term modeling and predictions. Nooner *et al.* (2006) used time-lapse seafloor gravity measurements to image and to put constraints on the *in situ* density of the CO_2. An *in situ* CO_2 density around 530 kg/m^3 is determined with uncertainty in determining the average density is estimated to be ±65 kg/ m^3 (95% confidence), however, additional seismic surveys are proposed before firm conclusions can be drawn. They have indicated that future gravity measurements will put better constraints on the CO_2 density and continue to map out the CO_2 flow.

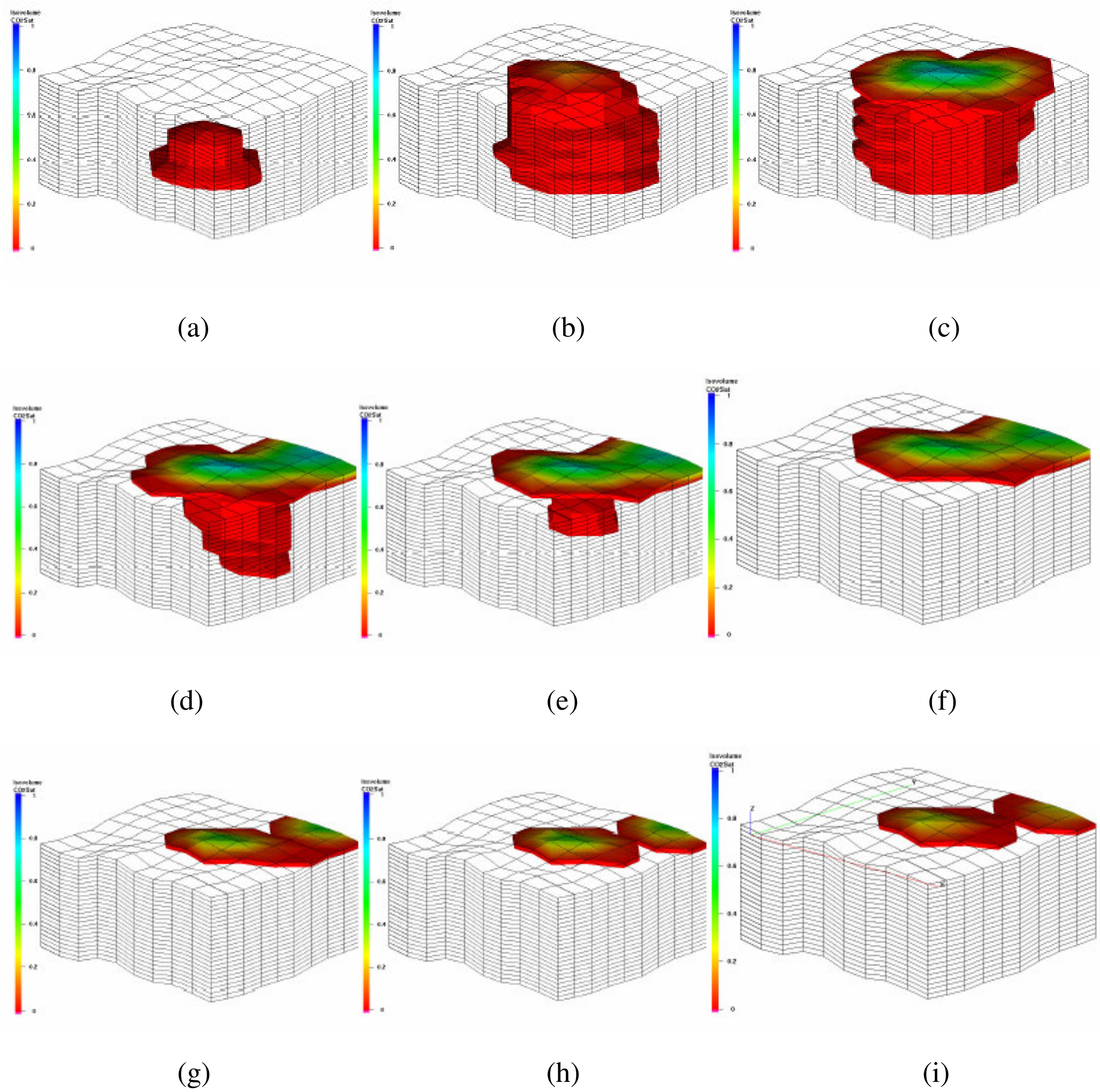

Figure 29: Spatial evolution of the CO_2 immiscible phase-isovolume of CO_2 after (a) 1 year, (b) 10 years, (c) 20 years, (d) 100 years, (e) 170 years, (f) 200 years, (g) 400 years, (h) 500 years, and (i) 1000 years simulations (after Khattri *et al.*, 2006)

Monitoring is also required to assess whole reservoir performance. Time-lapse 3D and 4D seismic surveys have been successfully employed to image the underground CO_2 (Arts *et al.* 2002, Chadwick *et al.* 2005). These studies were able to monitor the known injected amounts of CO_2, however, some aspects of reservoir structure and properties remained imperfectly understood and thus they could not provide a unique verification of complete reservoir behaviour (Chadwich *et al.*, 2006). Recent studies (Chadwich *et al.*, 2006) assessed the key aspects of the seismic data that constrain models of CO_2 migration through the reservoir. These key aspects of the seismic data comprise derivation of layer thicknesses from seismic amplitudes data (tuning), topographic analysis of the reservoir top versus CO_2 - water contact (static ponding), and thickness determination from combinations of the amplitudes and the structural analysis (Chadwich *et al.*, 2006). This study show that the topmost layer of the CO_2

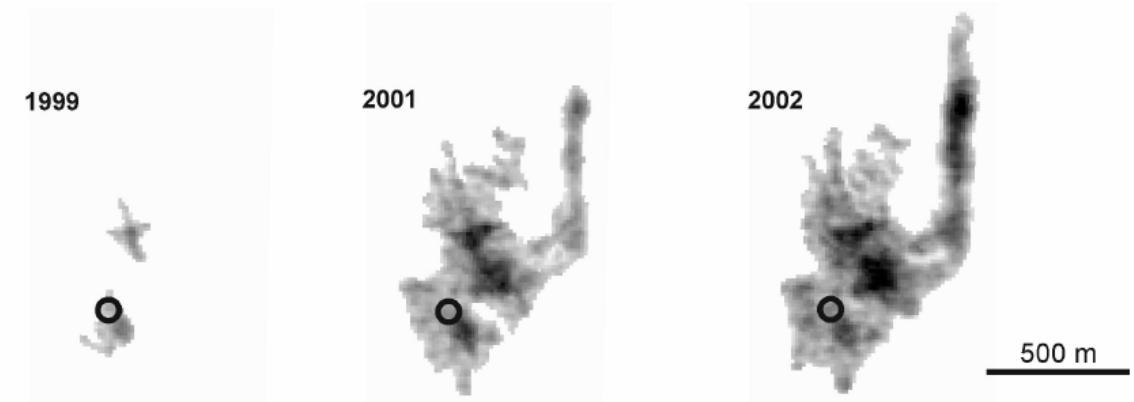

Figure 30: Growth of the topmost CO_2 layer mapped through time via seismic amplitudes (circle denotes location of injection point), Chadwick *et al.* 2006.

Table 7 Volume of CO2 in topmost layer computed from three different methods (Chadwick *et al.* 2006).

survey date	amplitudes and tuning (m^3)	static ponding (m^3)	amplitudes and structure (m^3)
1999	14573	12000	18086
2001	158087	127203	195831
2002	246914	222548	305418
2004		498027	611844

plume can be most accurately characterized, its rate of growth quantified, and CO_2 flux at the reservoir top estimated. Seismic reflection amplitude maps (Figure 30) show how the topmost layer has grown from two small patches in 1999 to an accumulation of considerable lateral extent by 2002. A north-trending linear prolongation is prominent, corresponding to CO_2 migrating northwards along a linear ridge at the reservoir top.

The volume of CO_2 within the topmost layer was computed for the three methods of thickness determination (Table 7), assuming a mean sand porosity of 0.38 with saturations computed using a laboratory determined relationship between buoyancy forces and capillary pressure. From the topmost layer volumes, the rate at which CO_2 has arrived at the top of the reservoir can be estimated. Taking, for example, the amplitude-structure thicknesses, an estimated 1.8 x 10^5 m^3 of CO_2 arrived at the reservoir top between the 1999 and 2001 surveys, an average flux of ~250 m^3 per day. Between the 2001 and 2002 surveys ~1.1 x 10^5 m^3 of CO_2 arrived at the reservoir top, an average flux of ~450 m^3 day^{-1}. Between the 2002 and 2004 surveys a further ~3.1 x 10^5 m^3 of CO_2 arrived at the reservoir top, averaging ~400 m^3 day^{-1}. These volumes correspond to ~3.7%, ~6.2 % and ~6.5% of the total amount of CO_2 injected during the respective periods. Measurements on the 2004 dataset are, as yet, preliminary, but the data nevertheless indicate an early increase in flux rates followed by stabilization. Comparisons of observed fluxes derived from the seismic data do not match the flow simulation in this study, due to the possibility that chemical reactions of CO_2 with mudstone mineralogies are producing new mineral phases capable of significantly reducing mudstone porosity and, by implication, permeability (Chadwich *et al*., 2006). The analysis indicates that, following early and quite rapid establishment of flow pathways, mudstone flow properties have remained fairly stable. This improves confidence in likely caprock stability in the presence of CO_2, and more generally in the validity of longer-term simulations of plume development.

8.5 Geological security

Geological security of carbon dioxide storage depends on a number of factors. The first and foremost prerequisite is a careful storage site selection. The storage site and its surroundings need to be characterized in terms of geology, hydrogeology, geochemistry and geomechanics (structural geology and deformation in response to stress changes). The greatest emphasis should be placed on the reservoir and its sealing horizons to avoid leakages through the seal and/or faults. At Sleipner, characterisation of the reservoir and caprock was carried out at a range of scales. Available geological information show that extensive rifting and normal faulting occurred in the North Sea and the Norwegian Sea before and during early Cenozoic (Paleogene period, 65-23 million years). The Utsira formation was deposited in late Middle Miocene (ca.20 million years) to Early Pliocene (~13 million years). Recent geological structures are associated with mud volcanoes and intraformational faults and are more likely to affect the underlying Oligocene (ca. 36 million years) sediments (Fabriol 2001). Microseismic studies show that the injection of CO_2 in sands of the Utsira Formation should not trigger any measurable microseismicity except in impermeable or semi-permeable shale lenses that block the rise of the CO_2 toward the top of the formation. Absence of major tectonic events after the deposition of the Utsira formation coupled with the evidence from microseismic studies further builds the confidence in geological security of carbon dioxide storage at Sleipner. Moreover, evidence (e.g. reservoir flow modelling and seismic monitoring of the injected CO_2) from ten years experience shows no leakages of carbon dioxide from storage site.

Monitoring is needed primarily to build our confidence in geological security of CO_2 storage. Specifically, to detect leakage and provide an early warning of any seepage or leakage that might require mitigating action. Also to ensure and document the injection process, verify the quantity of injected CO_2 that has been stored by various mechanisms and finally to demonstrate with appropriate monitoring techniques that CO_2 remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO_2 remains stored and that performance predictions can be verified and requires some combination of models and monitoring. At Sleipner the CO_2 injection process was monitored using seismic methods and this provided insights into the geometrical distribution of the injected CO_2. It also allowed increase understanding of the CO_2 migration within the reservoir.

The effectiveness of geological storage also depends on a combination of physical and geochemical trapping mechanisms (Section 3.2). The most effective storage sites are those where CO_2 is immobile because it is trapped permanently under a thick, low-permeability seal or is converted to solid minerals or through a combination of physical and chemical trapping mechanisms. Reservoir simulations were carried out successfully at both local and regional-scale models followed by a calibration of the local reservoir model to verify the seismic and geological interpretations and to predict the long-term fate of the stored CO_2. The results of the simulations show that most of the CO_2 accumulates in one bubble under the cap seal of the formation a few years after the injection is turned off. The CO_2 bubble spreads laterally on top of the brine column and the migration is controlled by the topography of the cap seal only. Thus preliminary results suggest that in the long term (> 50 years) the phase behaviour (solubility and density dependence of composition) will become the controlling fluid parameters at Sleipner. The primary benefit of solubility trapping is that once CO_2 is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upwards. Next, it will form ionic species as the rock dissolves, accompanied by a rise in the pH. Finally, some fraction may be converted to stable carbonate minerals (mineral trapping), the most permanent and secure form of geological storage. The recent studies at Sleipner area (Section 8.4) strengthens further the geological security of carbon dioxide storage in the Utsira formation.

Evidence from oil and gas fields indicates that hydrocarbons and other gases and fluids including CO_2 can remain trapped for millions of years (Magoon and Dow, 1994; Bradshaw *et al.*, 2005). Carbon dioxide has a tendency to remain in the subsurface (relative to hydrocarbons) via its many physicochemical immobilization mechanisms. World-class petroleum provinces have storage times for oil and gas of 5–100 million years, others for 350 million years, while some minor petroleum accumulations have been stored for up to 1400 million years. However, some natural traps do leak, which reinforces the need for careful site selection, characterization and injection practices.

8.6 Environmental issues

Carbon dioxide storage in geological formations is a safe way to achieve large-scale reductions in emissions. The dominant safety concern about geological storage is potential leaks that can cause potential local and regional environmental hazards. Leaks can either be slow or rapid. Gradual and dispersed leaks will have very different effects than episodic and isolated ones. The most frightening scenario would be a large, sudden, catastrophic leak. This kind of leak could be caused by a well blowout or reactivation of earlier unidentified geological structures due to for instance microseismic or earth quack events. The most noteworthy natural example of a catastrophic CO_2 release was in the deep tropical Lake Nyos in Cameroon in 1986 in which a huge released CO_2 gas cloud killed 1,700 people in a nearby village. A sudden leak also could result from a slow leak if the CO_2 is temporarily confined in the near-surface environment and then abruptly released.

CO_2 being a nontoxic at low concentrations can cause asphyxiation primarily by displacing oxygen at high concentrations. For large-scale operational CO_2 storage projects, assuming that sites are well selected, designed, operated and appropriately monitored, the balance of available evidence suggests that it is very likely the fraction of stored CO_2 retained is more than 99% over the first 1000 years, implying very negligible risks. However, should leaks occur, the possible local and regional environmental hazards are described in Section 6.4.

At Sleipner CO_2 storage project it is important to demonstrate through monitoring and verification procedures to detect potential leaks if any. Monitoring technology that can measure CO_2 concentrations in and around a storage location to verify effective containment of the gas needs to be placed. Leakage from a naturally occurring underground reservoir of CO_2 such as in Lake Nyos in Cameroon and in Mammoth Mountain, California, provides some perspective on the potential environmental effects. The leaking led to the death of plants, soil acidification, increased mobility of heavy metals and human fatality. These sites are a useful natural analog for understanding potential leakage risks, but for instance Mammoth Mountain is situated in a seismically active area, unlike the sedimentary basins where engineered CO_2 storage would take place. Still, we should be wary of undue optimism and continue to question the safety of artificial underground CO_2 storage. Given potential risks and uncertainties, the implementation of effective measurement, monitoring, and verification tools and procedures will play a critical role in managing the potential leakage risks. Continued research on the mobility of the injected CO_2 (and the risks associated with its leakage) should be high priorities. Risks associated with leakage from geologic reservoirs beneath the ocean floor are less than risks of leakage from reservoirs under land, because in the event of leakage, the dissipating CO_2 would diffuse into the ocean rather than re-entering the atmosphere. But then hazards to ecosystems will be of concern (Section 6.4.3).

8.7 Conclusions

The security of carbon dioxide storage in geological formations first and foremost depends on careful storage site selection followed by characterization of the selected site in terms of geology, hydrogeology, geochemistry and geomechanics (structural geology and deformation in response to stress changes). The Utsira Formation is well characterized with respect to porosity and permeability (good storage capacity and injectivity), mineralogy, bedding, depth, pressure and temperature. It is a very large aquifer with a thick and extensive claystone top seal. Available geological information shows absence of major tectonic events after the deposition of the Utsira formation. This means that the geological environment is tectonically stable which implies that the site is suitable for carbon dioxide storage. Microseismic studies suggest the injection of CO_2 in sands of the Utsira Formation has not trigged any measurable microseismicity. This further builds the confidence in geological security of carbon dioxide storage at Sleipner. Moreover, evidence from ten years experience of carbon dioxide storage shows no leakages.

The Sleipner project is a commercial CO_2 injection project and proved that CO_2 capture and storage is a technically feasible and effective method for greenhouse mitigation. It further demonstrates that CO_2 storage is both safe and has a low environmental impact. Monitoring is needed for a wide variety of purposes. Specifically, to ensure and document the injection process, verify the quantity of injected CO_2 that has been stored by various mechanisms, demonstrate with appropriate monitoring techniques that CO_2 remains contained in the intended storage formation(s). This is currently the principal method for assuring that the CO_2 remains stored and that performance predictions can be verified. Finally monitoring is required to detect leakage and provide an early warning of any seepage or leakage that might require mitigating action and to assess environmental effects. The work that has been undertaken at Sleipner Gas Field has shown that the injected CO_2 can be monitored within a geological storage reservoir, using seismic surveying. The geochemical and reservoir simulation work have laid the foundations to show how the CO_2 has reacted and what its long term fate in the reservoir will be. The results of the simulations indicate that most of the CO_2 accumulates in a stack of accumulations under thin clay layers interbedded in the sand unit few years after the injection is turned off. The CO_2 plume spreads laterally on top of the brine column and the migration is controlled by the interbedded thin clay layers within the sand unit. In the long term (> 50 years) the phase behaviour (solubility and density dependence of composition) will become the controlling fluid parameters at Sleipner. The solubility trapping has the effect of eliminating the buoyant forces that drive CO_2 upwards and through time can lead to mineral trapping, which is the most permanent and secure form of geological storage.

The recent studies at Sleipner area reveal the integrity of the cap rock (efficient sealing capacity). The injected CO_2 will potentially be trapped geochemically and the regional groundwater flow having an effect on the distribution of CO_2 with the potential of pressure build up as a result of CO_2 injection is unlikely to occur. Monitoring techniques (both Time-lapse Gravity and Seismic methods) proved to be key tools in understanding the whole-reservoir performance. Overall, the recent studies at Sleipner area demonstrate further the geological security of carbon dioxide storage and the monitoring tools strengthen verification of safe injection of CO_2 in the Utsira formation. Subsequent work in the following years is necessary to reinforce these findings further that CO_2 storage is safe through monitoring and verification procedures that will be able to detect potential leaks.

8.8 Recommendations

Several CO_2 storage projects are now in operation and being carefully monitored. No leakage of stored CO_2 out of the storage formations has been observed in any of the current projects. Although time is too short to enable direct empirical conclusions about the long-term performance of geological storage, it is an indication that CO_2 can be safely injected and stored at well characterized and properly managed sites. Monitoring of existing projects in the coming 10-20 years is crucial to the broader understanding of CO_2 transport, trapping mechanisms and storage security and to predict long-duration performance. However, if leaks occur, tools for monitoring possible local and regional environmental hazards should be in place together with remediation measures. In this section general recommendations which are thought to contribute to better understanding of geological storage of CO_2 with regard to security and environmental safety. Also the measures needed to be taken in future are listed below.

1) Storage capacity determination for large scale carbon dioxide storage should be determined as accurately as possible. The problem of heterogeneity and porosity should be assessed carefully. Reaction of the CO_2 with formation water and rocks may result in reaction products that affect the porosity of the rock and the flow of solution through the pores. This possibility has not been observed experimentally and its possible effects are not quantified. It is important to assess these effects to get better knowledge about the reservoir and migration patterns of the injected CO_2.
2) During site characterization greatest emphasis are placed on the reservoir and its sealing horizons. However, the strata above the storage formation and caprock also need to be assessed because if CO_2 leaked it would migrate through them.
3) Geological storage projects will be selected and operated to avoid leakage. However, in rare cases, leakage may occur and remediation measures will be needed, either to stop the leak or to prevent human or ecosystem impact. Moreover, the availability of remediation options may provide an additional level of assurance to the public that geological storage can be safe and effective. Therefore appropriate remediation options must be identified in an event of a leakage scenario.
4) The Utsira Formation is a very large aquifer with a thick and extensive claystone top seal. The aquifer is, however, unconfined along its margins. It is important to assess the time required for the migrating CO_2 to reach at the margins of the aquifer.
5) To predict the migration of CO_2 over a period of several thousand years a coarse grid model was used due to computational constraints. However, grid patterns may miss narrow linear anomalies or patterns of linear features on the surface that may reflect deeper fault and fracture systems, which could become natural migration pathways. Future modelling should account such uncertainties.
6) During the SACS project (Best Practice Manual, 2004), the lack of observation boreholes and related samples made it impossible to monitor directly the geochemical processes occurring within the Utsira at Sleipner. Also the interactions of CO_2 with

borehole cement were not addressed in the study. Assessment of both issues should be a priority in future monitoring activities.

7) Evaluations on the risk of leakage through injection well, seal, and stress release events due to injection of CO_2 and their probabilities on the release of CO_2 should be a priority. Moreover, quantification of the short-term and long-term Health-Safety-Environmental (HSE) risks, in this case the likelihood of impacts on human and marine life should be assessed.
8) Finally further research on the processes involved in both sealing and in migration of CO_2 in the underground and improved modelling tools is needed to predict future behaviour of a storage location. Modelling tools need to be improved through calibration on real life experiments. Demonstration under different geological conditions is also pointed as important both for improving the understanding but also to prove to the public that storage are safe.

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