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

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Summary

Carbon dioxide capture and storage (CCS) is one option for mitigatining atmospheric emissions of carbon dioxide and thereby contributes in actions for stabilization of atmospheric greenhouse gas concentrations. 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) projects indicate that it is feasible to safely 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. 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 the Sleipner Gas Field since 1996. 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. The injected CO_2 will potentially be trapped geochemically pressure build up as a result of CO_2 injection is unlikely to occur. Solubility and density dependence of CO_2-water 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 it can lead to mineral trapping, which is the most permanent and secure form of geological storage. Overall, the study at the Sleipner area demonstrates the geological security of carbon dioxide storage. The monitoring tools strengthen the verification of safe injection of CO_2 in the Utsira formation. This proves that CO_2 capture and storage is technically feasible and can be an effective method for greenhouse mitigation provided the site is well characterized and monitored properly.

1 Introduction

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 increasing 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 ^oC from 1990 to 2100, according to The Intergovernmental Panel on Climate Change (IPCC, 2001c). An increase in global temperature by more than 2 ^oC will have dramatic impacts on life on earth. 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 climatesystems.

Several technological options for reducing net CO_2 emissions to the atmosphere exist

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(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. Improvements in energy efficiency have the potential to reduce global CO_2 emissions by 30% using existing technologies (IPCC, 2005). 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 (CCS) 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 IPCC has stated that global GHG emissions should be reduced by 50 to 80 % within 2050. In order to obtain such a huge emission reduction, a combination of increasing energy efficiency, switching from fossil fuel to renewable energy sources, and wide implementation of CCS is necessary (Stangeland, 2006). If CCS is fully implemented there is a potential of capturing and storing 240 billion ton CO_2 globally by 2050 (Stangeland, 2006). This corresponds to a 37 % reduction in global CO_2 emissions in 2050 compared to emissions today which indicates that only CCS is not enough to meet the targeted CO_2 emission reduction.

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 fossil fuels production. CO_2 capture technology can be applied to fossil-fuelled power plants and other large industrial sources of emissions; it can also be applied in the manufacture of hydrogen as an energy carrier as well as biomass.

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) 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. Injecting CO_2 into deep geological formations at carefully selected sites can store it underground for long periods of time.

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). This paper analyzes the current state of knowledge about the scientific and technical dimensions of CO_2 storage option with emphasis on geological storage, security and environmental impacts.

This paper reviews literature published on geological storage of carbon dioxide in deep saline aquifers with emphasis on the Sleipner Gas Field project in Norway. Sections 2-6 give detail on the technical aspects of geological storage of CO_2. After reviewing the current state of knowledge, the existing gaps in knowledge are outlined in Section 7 before a case study from the Sleipner Gas Field in Norway is presented in Section 8. This is followed by the conclusions drawn in Section 9.

2 Geological Framework

2.1 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 1). Other geological formations which may serve as storage sites include caverns, basalt and organic-rich shales.

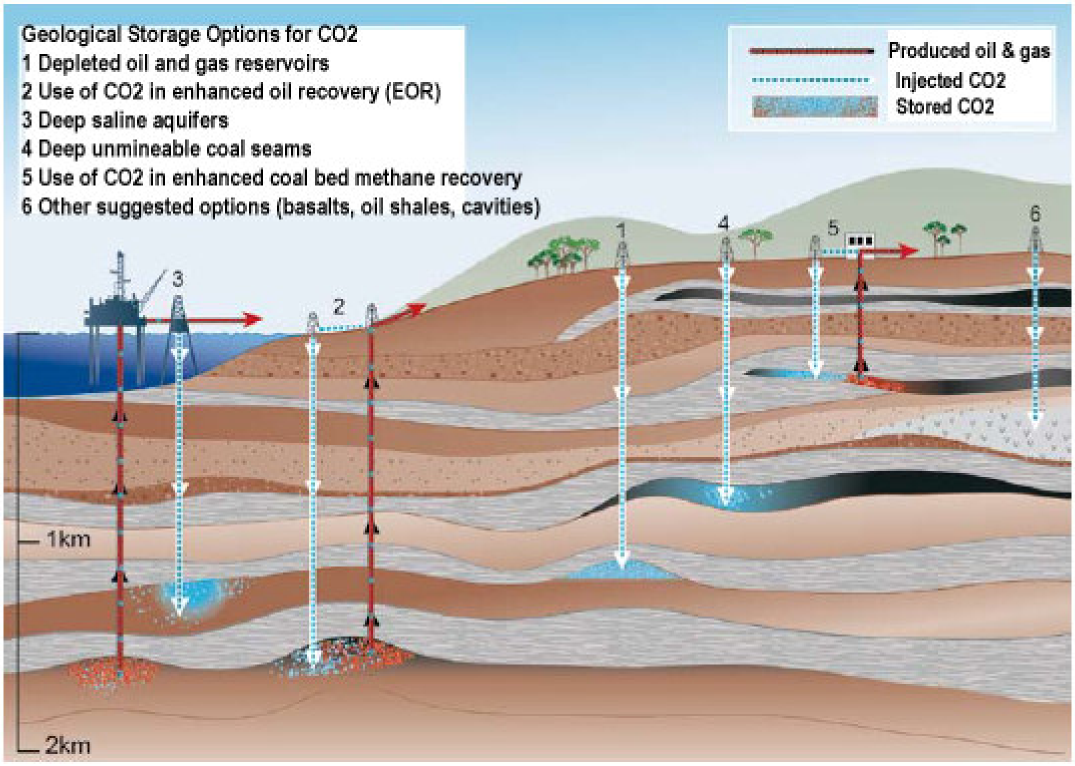

Figure 1: Options for storing CO_2 in deep underground geological formations (source IPCC 2005).

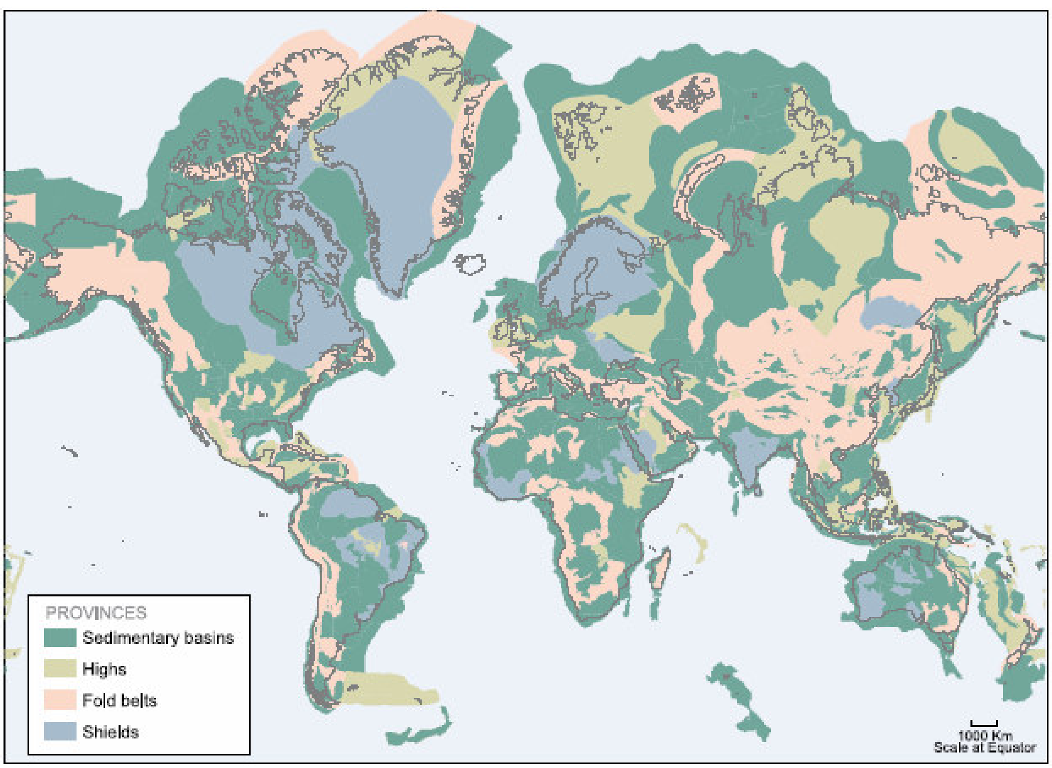

Figure 2: Distribution of sedimentary basins around the world. In general, sedimentary basins are likely to be the most prospective areas for storage sites. However, storage sites may also be found in some areas of fold belts and in some of the highs. Shield areas constitute regions with low prospectivity for storage. (Source IPCC, 2005).

In this study emphasis is given to deep saline aquifer 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 formations occur in sedimentary basins throughout the world (Figure 2), both onshore and on the continental shelves and are not limited to hydrocarbon provinces or coal basins. 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 Section 8.

2.2 Storage requirements

There are many sedimentary regions in the world (Figure 2) 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.

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.

The pressure and flow regimes of formation waters in a sedimentary basin are important factors in selecting sites for CO_2 storage (Bachu *et al.*, 1994). Injection of CO_2 into formations overpressured by compaction and/or hydrocarbon generation may raise technological and safety issues that make them unsuitable. Underpressured formations in basins located midcontinent, 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.

To geologically store CO_2, it must first be compressed to allow injection, 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, i.e. carbon dioxide (temperatures higher than 31.1^{o}C and pressure 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 about 800 m or greater, where the injected CO_2 will be in a dense supercritical state. 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.

'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).

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 (Kovscek, 2002; Flett *et al.*, 2005).

The presence of impurities (e.g., SO_x, NO_x, H_2S) 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. Gas impurities in the CO_2 stream affect the compressibility of the injected CO_2 (and hence the total volume to stored) and reduce the capacity for storage in free phase, because of the storage space taken by these gases. 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.

3 Storage mechanisms and storage security

The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms. 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.

3.1 Storage mechanisms

The storage mechanism known as 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 1). 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).

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 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).

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, a mechanism known as Geochemical trapping. 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 thousands of 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 longterm storage.

3.2 Storage security

Natural geological accumulation of CO_2 occur, as gaseous accumulations of CO_2, CO_2

mixed with natural gas, and CO_2 dissolved in formation water. These natural accumulations have been studied in the United States, Australia and Europe (e.g. Pearce *et al.*, 1996; 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. 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 and in faulted areas or in quiescent volcanic structures.

For instance, 200 Mt trapped in the Pisgah Anticline, northeast of the Jackson Dome in the USA, 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. Conversely, some systems, typically spas and volcanic systems, are leaky and not useful analogues for geological storage, but can be useful for studying the health, safety and environmental effects of CO_2 leakage.

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 in many parts of the world. 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. 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 (Lippmann and Benson, 2003; Perry, 2005).

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. Carbon dioxide often represents the largest component of the injected acid gas stream, in nodt 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 m^3 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 occurs over a wide range of formation and reservoir types.

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 34.1 million m^3 of hazardous waste is injected into saline formations in the United States from about 500 wells each year (IPCC, 2005). In addition, more than 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.

4 Site characterization and performance prediction

4.1 Site characterization

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. These include:

- core and fluids produced from wells at or near the proposed storage site
- pressure transient tests conducted to test seal efficiency

- 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.

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. These are listed below:

- Geological site description from wellbores 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, and
- Water quality samples are needed to demonstrate the isolation between deep and shallow groundwater.

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. Modelling 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 calibrated 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.

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 (e.g. White and Oostrom, 1997; Steefel, 2001; Xu *et al.*, 2003).

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 proves that the model is inaccurate, but it does provide additional constraints on the model parameters. However, better models and simulation tools are required.

5 Monitoring and verification

Monitoring is needed for a wide variety of purposes. It 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 pressure and formation pressures. Monitoring also can serve as a verification tool to quantify the injected CO_2 that has been stored by various mechanisms; and 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. It can also be applied to detect leakage and provide an early warning of any seepage or leakage that might require mitigating action.

Before monitoring of subsurface storage can take place effectively, a baseline survey must be taken. This survey will provide 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 baselines 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.

Standard procedures of monitoring currently in use include:

- routine measurements of injection rates and pressures,
- monitoring the distribution and migration of CO_2 in the subsurface,
- monitoring injection well integrity,
- monitoring local environmental effects, and
- monitoring 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).

A number of standard technologies are available for monitoring but the applicability and sensitivity of the techniques in use are somewhat site-specific. Given the long-term nature of CO_2 storage, site monitoring may be required for vey long periods.

6 Risk assessment and environmental impact

The risks due to storage of CO_2 in geological reservoirs fall into two broad categories: global risks and local risks. Global risks involve the release of stored CO_2 to the atmosphere that may contribute significantly to climate change if some fraction leaks from the storage formation. In addition, if CO_2 leaks out of storage formation, local risks include hazards for humans, ecosystems and groundwater.

With regard to global risks, observations and analysis of current CO_2 storage sites, natural systems, engineering systems and models indicate that the likelihood or probalility of leakage in appropriately selected and managed reservoirs is nearly absent or very negligible over long periods of time. The risk of leakage is expected to decrease over time as other mechanisms provide additional trapping.

With regard to local risks, there are two types of scenarios in which leakage may occur. In the first case, injection well failures or leakage up abandoned wells could create a sudden and rapid release of CO_2. This type of release is likely to be detected quickly and stopped using techniques that are available today for containing well blow-outs. Hazards associated with this type of release primarily affect living species in the vicinity of the release at the time it occurs, or workers called in to control the blow-out. A concentration of CO_2 greater than 7–10% in air would cause immediate dangers to human life and health.

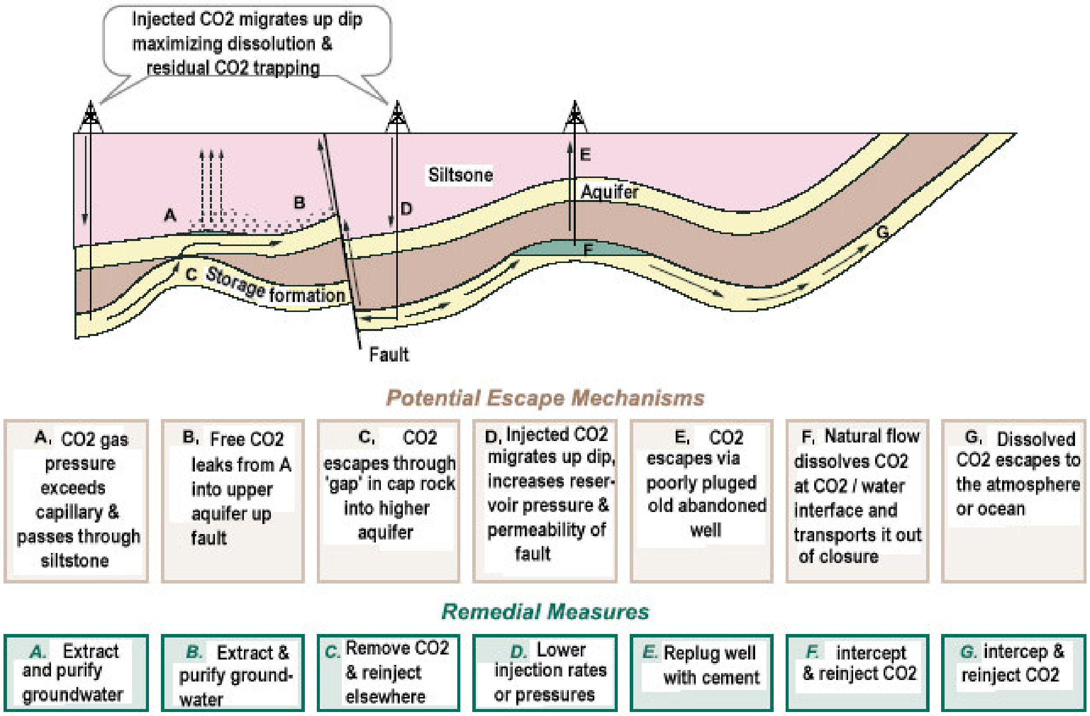

Figure 3: Some potential escape routes for CO_2 injected into saline formations (IPCC, 2005).

Containing these kinds of releases may take hours to days and the overall amount of CO_2 released is likely to be very small compared to the total amount injected. These types of hazards are managed effectively on a regular basis in the oil and gas industry using engineering and administrative controls.

In the second scenario, leakage could occur through undetected faults, fractures or through leaking wells where the release to the surface is more gradual and diffuse. In this case, hazards primarily affect drinking-water aquifers and ecosystems where CO_2 accumulates in the zone between the surface and the top of the water table. Groundwater can be affected both by CO_2 leaking directly into an aquifer and by brines that enter the aquifer as a result of being displaced by CO_2 during the injection process. There may also be acidification of soils and displacement of oxygen in soils in this scenario. Additionally, if leakage to the atmosphere were to occur in low-lying areas with little wind, or in sumps and basements overlying these diffuse leaks, humans and animals would be harmed if a leak were to go undetected. Humans would be less affected by leakage from offshore storage locations than from onshore storage locations. Leakage routes can be identified by several techniques and by characterization of the reservoir. Figure 8 shows some of the potential leakage paths for a saline formation. When the potential leakage routes are known, the monitoring and remediation strategy can be adapted to address the potential leakage.

Careful storage system design and site selection, together with methods for early detection of leakage (preferably long before CO_2 reaches the land surface), are effective ways of reducing hazards associated with diffuse leakage. The available monitoring methods are promising, but more experience is needed to establish detection levels and resolution. Once leakages are detected, some remediation techniques are available to stop or control them. Depending on the type of leakage, these techniques could involve standard well repair techniques, or the extraction of CO_2 by intercepting its leak into a shallow groundwater aquifer (see Figure 3).

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 summarised what are known now and what gaps remain. Gaps in the knowledge of geological storage of CO_2 are presented in this paper in accordance to the rating on the scale (1-5) given in the Review of Special Report on Carbon dioxide Capture and Sstorage Gaps in Knowledge (IPCC, 2006). The scales are: (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, and (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, particulary for aquifers. This knowledge is needed to determine effective capacity for CO_2 storage in geological formations to derive policy and research initiatives. There is need for a full global data set – presently most data set is from Australian, Japan, North America and Western Europe.

B) Improved Confidence

Risks of leakage from abandoned wells and methods of leakage need to be determined.
Assessment of the environmental impact of CO_2 seepage on the marine seafloor is required. Also quantitative assessment of risks to human health is required. Besides more leakage rates data from more storage sites or projects need to be collected. Development of a reliable coupledhydrogeological-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. 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.

Unimportant (5) knowledge gaps on geological storage of CO_2 do not need to be addressed. However, knowledge gaps in the categories (3) and (4) can be found in detail (IPCC, 2006).

8 Case study - The Sleipner Gas field

8.1 Background

The offshore gas field Sleipner, in the middle of the North Sea (Figure 4), has been injecting 1 Mt CO_2 per year since September 1996 (Baklid *et al.,* 1996). 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. The CO_2 is injected into a salt water containing sand layer, called the Utsira formation, which lies 1000 meter below sea bottom. The Utsira Formation was deposited during the late Middle Miocene (~20 million years ago) to Early Pliocene (~14 million years ago), Eidvin et al. 2002. The formation belongs to the Nordland Group present in the Viking Graben (Gregersen and Michelsen 1997).

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 (supported under the European Commission's Thermie Programme) and started to collect relevant information about the injection of CO_2 into the Utsira formation and similar underground structures around the North Sea.

Figure 4: Location map showng areal extent of the Utsira Formation and the Sleipner licence.

In 1999 the SACS (Phase 1) project 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 and 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. The SACS2 project terminated in 2003.

The document Best Practice Manual (Best Practice Manual, 2004) outlines the main findings of the SACS projects. This paper reviews this document including recent studies with emphasis on geological security and environmental issues in this section.

8.2 Site characterisation

Characterisation of both the reservoir and caprock was carried out both at local and regional scales. The whole reservoir 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. Several datasets were available to the SACS project (See Best Practice Manual, 2004 for details).

The 2D and 3D seismic data constituted the key datasets, essential for delineating the reservoir limits, structure and stratigraphical correlation (Figure 5a). 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 site characterization for CO_2 storage (Figure 5b). 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 5c).

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 (Figure 5b). The distance from the top Utsira formation to the surface generally varies relatively smoothly, mainly in the range 550 to 1500 m, but mostly from 700 to 1000 m. The thicknesses of the sand layer vary from 200 m and range up to more than 300 m locally (Chadwick *et al.,* 2000).

During the SACS-project, it has been shown that the Utsira Formation has good storage quality with respect to porosity, permeability, mineralogy (Table 1), 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 with good sealing capacity. The aquifer is, however, unconfined along its margins, and the time before migrating CO_2 might reach the margins of the aquifer is unknown.

It is estimated that the Utsira Formation, below 800 m depth, has a pore volume of 9.18 x 10^{11} m^3, a storage capacity in traps of 847 Mt (megatonnes) CO_2, and that the storage capacity of the entire aquifer is 42 356 Mt CO_2 (See details in Bøe et al. 2002, Table 6). The total pore volume of the aquifer is also estimated to be 5.5 x 10^{11} m^3 (Kirby *et al.* 2001) and 6.05 x 10^{11} m^3 (Chadwick et al. 2000).
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 CO_2 plume).

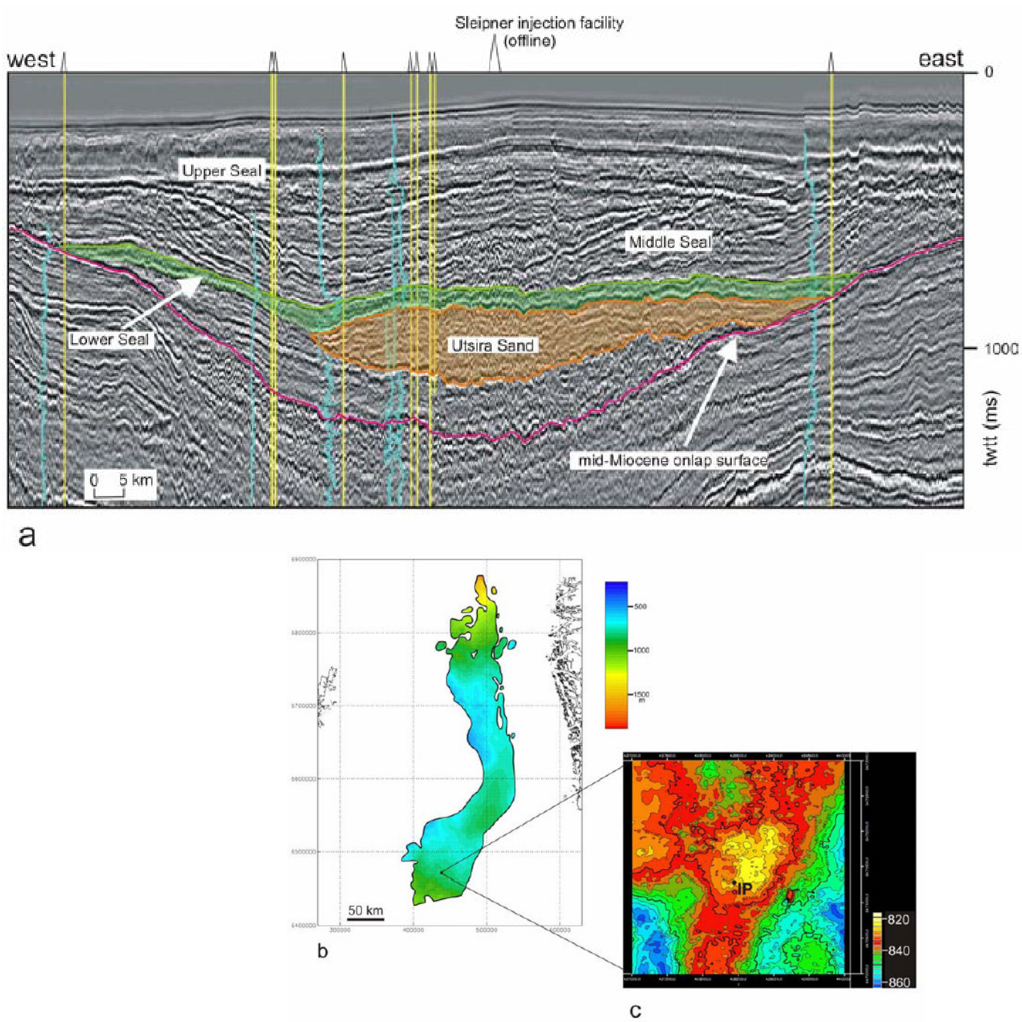

Figure 5: a) Typical 2D seismic reflection profile across the Utsira reservoir b) Regional depth map to top of Utsira Sand based on 2D seismic surveys and incorporating 3D data around Sleipner injection point. c) Detailed depth map of Top Utsira Sand around Sleipner injection point (IP), based on 3D seismic data. (Best Practice Manual, 2004).

Table 1 Generalised properties of the Utsira Sand from core and cuttings. Mineral percentages based on whole-rock XRD (x-ray diffraction) analysis. (Best Practice Manual, 2004).

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

8.3 Monitoring

Work at Sleipner demonstrated that conventional, time-lapse, p-wave seismic data can be a successful monitoring tool for CO_2 injected into a saline aquifer with CO_2 accumulations as low as about a metre thick (Eiken et al. 2000). It is the detection of relatively thin CO_2 accumulations on the time lapse seismic signal 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.

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 indicated in Figure 6. Due to the lower density of CO_2 with respect to the formation water, bouyancy 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 locations chimneys have been observed where CO_2 passes through the thin shale layers. 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. 6). 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 (Torp and Gale, 2004).

Monitoring is also used to assess whole reservoir performance. Time-lapse 3D and 4D seismic surveys have been successfully employed to image the underground CO_2 (Chadwick *et al.* 2005; Figure 5 and 6). 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 (Chadwick *et al.*, 2006). The Key aspects of the seismic data that constrain models of CO_2 migration through the reservoir were assessed at Sleipner (Chadwich *et al.*, 2006). 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). Their study has shown that the topmost layer of the CO_2 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 7) show how the topmost layer has grown from two small patches in 1999 to an accumulation of considerable lateral extent by 2002.

The volume of CO_2 within the topmost layer was computed for three methods of thickness determination (Table 2), 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 was 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. 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

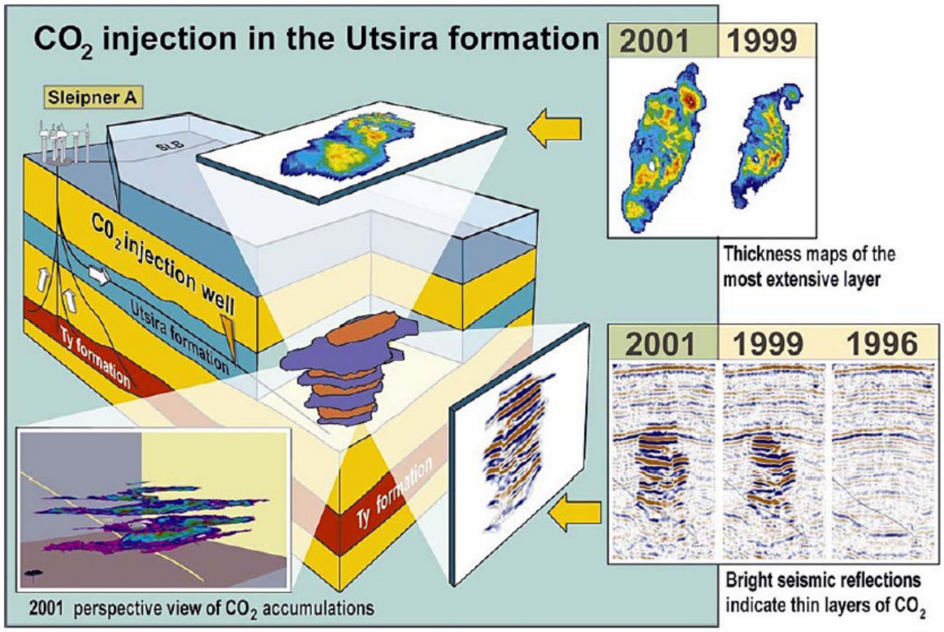

Figure 6: Repeat seismic surveys and position of injected CO_2 (Source Torp and Gale, 2004).

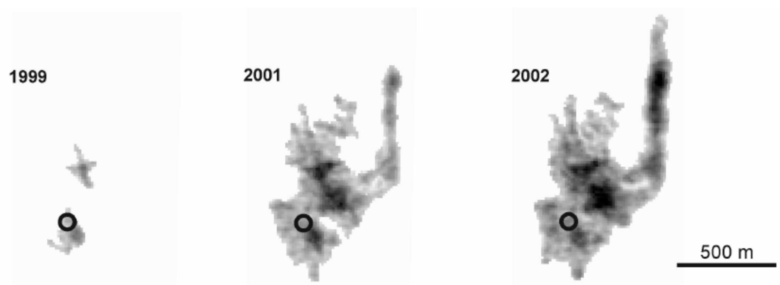

Figure 7: Growth of the topmost CO_2 layer mapped through time via seismic amplitudes (circle denotes location of injection point), Chadwick *et al.* 2006.

Table 2 Volume of CO_2 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

validity of longer-term simulations of plume development (Chadwich *et al*., 2006).

8.4 Reservoir simulation

Reservoir simulation was carried out to verify and improve the seismic and geological interpretations of the reservoir around the injection site. Moreover to 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.

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 good matches between observed and simulated bubble areas even if CO_2 solubility was completely neglected (Best Practice Manual, 2004). From this it was also 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, rather it is concentrated at localised spill points, curtains, or holes.

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. The results of the simulations show that most of the CO_2 accumulates in one bubble under the cap seal 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.

It has been shown that 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.

Reservoir simulations under various scenarios were tested to predict the long-term fate of CO_2 (Best Practice Manual, 2004). The results show that 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 is commonly called solubility trapping (Section 3.1). 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.

During and after the injection of 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. Their analyses show that immiscible CO_2 is mobilized due to buoyancy forces, and the immiscible CO_2 get carried away by the regional water flow. 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.

8.5 Geochemical characterization

It is essential to have a good understanding of the fluid chemistry and mineralogical composition of reservoir and caprock so as to elucidate their reactivity with CO_2.

At the start, 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 geochemical characterization and modelling work (Best Practice Manual, 2004). In general, the Utsira sand showed only limited reaction with CO_2. Most reaction occurred with carbonate phases (shell fragments), but these were a minor proportion (about 3%; Table 1) 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.

Recent studies strengthen further these observations while assessing the behaviour of CO_2 with the reservoir seal. Earlier observations from laboratory experiments during the SACS project show that 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 and Sr), 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. Numerical modelling was used to interpret, and hence to better understand the laboratory experiments, based on thermodynamic, kinetic, flow and transport processes. For most of the major elements, the predicted trends were in reasonable agrement with the experimental observations on the Utsira sand.

The impact of CO_2 storage on the Utsira reservoir and its cap rock at Sliepner was studied using a long term coupled transport and geochemical modelling (Gaus *et al.* 2006). This is a key to understanding the long term geochemical impact of CO_2 storage. Results on impact of dissolved CO_2 on the cap rock after 3000 years at Sleipner shows that vertical diffusion of CO_2 can be retarded as a consequence of geochemical interactions. The calculated porosity change was found to be small and limited to the lower few metres of the cap rock. The calculations were positive with respect to the sealing efficiency meaning slight improvement of the cap rock sealing capacity. Moreover, at the cap rock/reservoir interface minor carbonate dissolution is expected to occur. Overall in the Utsira case geochemical reactions, other than dissolution of CO_2 with pH change, are unlikely to play a major role due to its low reservoir temperature (37°C) leading to very slow reaction kinetics and little reactive mineralogy. After a 10 000 year simulation Gaus *et al.* 2006 concluded that CO_2 is completely dissolved in the formation water due to carbonate dissolution and in the form of bicarbonate ions. Main mineralogical changes take place where the dense temporary CO_2 bubble was present and there most of the carbonates dissolve.

Caprock properties of the Nordland Shale recovered from the 15/9-A11 well, was assessed for intergrity at the Sleipner area (Springe and Lindgren, 2006). The results show that the CO_2 bubble spreading beneath the seal is unlikely to enter the Nordland Shale, implying good sealing capacity. However, this conclusion may change if regional variation in grain size exceeds the range observed in the 15/9-A11 well.

8.6 Geological security

Geological security of carbon dioxide storage depends on a number of factors. The first and formost prerequisite is a carefull storage site selection. 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 ago). The Utsira formation was deposited in late Middle Miocene (ca.20 million years ago) to Early Pliocene (~13 million years ago). 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 measureable microseismicity. 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. 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 and to make storage inventory and verification of CO_2 injection. This is a key tool to assess potential leakage.

The results of reserviour simulations and geochemical characterization show that the CO_2 bubble will in the long term be dissolved with the phase behaviour (solubility and density dependence of composition) as controlling fluid parameters at the early stage. 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 strengthens further the geological security of carbon dioxide storage in the Utsira formation. Moreover regional flow can have dramatic effect on the CO_2 distribution. This hints further that pressure build up as a consequence of CO_2 injection is unlikely to occur and eliminating the prospects of CO_2 leaks.

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.

8.7 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 those described in Section 6.

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 provides some perspective on the potential environmental impacts. The leaking led to the death of plants, soil acidification, increased mobility of heavy metals and human fatality. This site can be a useful natural analog for understanding potential leakage risks, but it 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 reentering the atmosphere. But then hazards to marine ecosystems will be of concern.

9 Conclusions

The security of carbon dioxide storage in geological formations first and foremost depends on carefull storage site selection followed by characterization of the selected site. 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 implies that the geological environment is tectonically stable and a site suitable for carbon dioxide storage. Microseismic studies suggest that the injection of CO_2 in sands of the Utsira Formation can not trigger any measureable 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 has demonstrated that CO_2 storage is both safe and has a low environmental impact. 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 injected CO_2 will potentially be trapped geochemically and pressure build up as a result of CO_2 injection is unlikely to occur. In the long term 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 the Sleipner area reenforce the integrity of the cap rock and there is efficient sealing capacity. Monitoring and modelling proved to be key tools in understanding the whole reservoir performance. Overall, the study at the Sleipner area demonstrates the geological security of carbon dioxide storage. The monitoring tools strengthen the verification of safe injection of CO_2 in the Utsira formation. This proves that CO_2 capture and storage is technically feasible and can be an effective method for greenhouse mitigation provided the site is well characterized and monitored properly.

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