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NFR CLIMIT Project Nr. 176004/I30
Deliverable D1.1 Compilation of estimation procedures for discrete leak paths related to CO_2 geological storage

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REPORT

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NFR CLIMIT Project nr. 176004/I30 Deliverable D1.1 Compilation of estimation procedures for discrete leak paths related to CO_2 geologic storage

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Summary:

The ultimate objective of this project is to contribute directly to establishing necessary confidence that the CO_2 in specific geological storage sites will be effectively retained for a time scale of thousands of years. This project will address the specific needs of 3rd party independent verification of geologic storage sites.

This document focuses on Sub Project 1 (SP1):
Focused procedures for evaluation of the leak potential of discrete leak paths.

Tasks in Work package 1.1: Compilation of estimation procedures for discrete leak paths:

- Literature review
- Develop calculation procedures

The emphasis will be on the ability to map and describe discrete leakage paths before they can be represented in integrated simulation models.

This document aims to describe in detail the procedures to be applied by a verifier of a potential CO_2 geologic storage site as related to identifying all discrete leakage pathways, including all relevant faults, fractures, thief zones and wellbores, as well as their key characteristics, in order to judge to which extent that these might compromise the storage containment requirements of the site.

Keywords: Sedimentary basin	Hydrocarbon reservoir	Aquifer
CO_2	Storage	Migration
Faults	Fractures	Leakage

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1. INTRODUCTION

Although the purpose of CO_2 geologic storage (also known as sequestration) is to trap all CO_2 captured from point sources in the subsurface, there is a potential for CO_2 to escape by migrating along permeable pathways such as fractures, faults, thief zones and wellbores. The escaped CO_2 can degrade underground sources of drinking water, or re-enter the surface soils and/or atmosphere, and thereby negate the purpose of the geologic storage. It is assumed that proper site selection, carefully controlled injection operations and site monitoring will minimize the fluxes of CO_2 entering the hydrosphere/atmosphere along such avenues. If CO_2 geologic storage is to contribute to reducing the risk of anthropogenic climate change, it must deliver effective storage on the time scale of 5000-10000 years (Chadwick et al. 2001, Lindeberg 2002, Hepple and Benson, 2002; Oldenburg et al., 2003, Chadwick et al. 2004a and b, Benson 2006). Policy makers and society need confidence that the technology can achieve this before they will accept and ultimately pay for CO_2 geologic storage.

In view of these concerns related to the required effectiveness of subsurface CO_2 storage, it is necessary to develop fit-for-purpose strategies, methodologies and systems aimed at verifying long-term storage in which the primary technology strategy is to avoid and otherwise minimise CO_2 movement to the surface.

In general, a geological site where effective long-term trapping can be reasonably expected for CO_2 storage is characterized by (IEA 2004):

- Lithologically competent bounding seals
- Hydraulic isolation from overlying sources of drinking water
- An appropriate hydrogeological regime
- Minimal potential for migration of CO_2 along faults, fractures, thief zones or abandoned wellbores.

An important additional consideration for choosing a particular site for CO_2 storage can be movement of fluids displaced by the stored CO_2, and whether they will contaminate underground sources of drinking water or taint surface environments.

The desired conditions for CO_2 geologic storage are found only in sedimentary basins, and site assessment must begin with an understanding of basin-scale features in the underground and up to surface. Identification of such conditions involves a relatively detailed mapping of the major features of the geosphere in the subsurface volume that includes, lies above or is otherwise nearby the expected maximum extent of the CO_2 plume. This implies mapping the geology, stratigraphic position, distribution and extent of reservoirs, seals, regional aquifers, and aquitards from the Precambrian basement to the ground surface. The complexity and diversity of plate-tectonics and sedimentary processes and history make each sedimentary basin and potential storage site unique.

This document aims to describe in detail the procedures to be applied by a verifier of a potential CO_2 geologic storage site as related to identifying all discrete leakage pathways, including all relevant faults, fractures, thief zones and wellbores, as well their key characteristics, in order to judge to the extent that these might compromise the storage containment requirements of the site.

2. INITIAL SITE DATA COLLECTION AND DESCRIPTION

Much of the risk of leakage and seepage from geological storage is related to the buoyant condition of CO_2 at typical underground conditions. Free CO_2 phase is buoyant relative to reservoir brines at any and all conceivable geologic reservoir pressures and temperatures and geologic storage situations. This means that it will tend to rise to the top of the brine-filled storage reservoir until it is stopped by either a hydrodynamic trap, it is effectively smeared completely out as an immobile saturation, or it dissolves into the reservoir brine, at which point it is no longer buoyant[1]. If the buoyant CO_2 is not stopped by the primary cap rock barrier, it will then rise until a new attenuating or trapping feature or process stops it, or it will continue its upward movement until it escapes to the atmosphere.

This implies that verifying the long-term containment effectiveness of geologic storage performance requires estimating the amount of potential movement of stored CO_2 out of its targeted storage reservoir. This implies further that a sufficiently detailed map is produced of the storage reservoir, its caprock barrier (seal), any traps defined by sealing faults, and any relevant features that may allow CO_2 to escape from the storage reservoir and ultimately reach the vadose[2] zone and the atmosphere over a sufficiently long time frame. The current best estimate of the mean retention time of storage to be effective as a climate change mitigation option is 5000-10000 years (Lindeberg and Bergmo 2002, Lindeberg 2003).

The initial data collection and mapping phase will require

- Regional basin data (i.e. much larger area than the candidate storage site) on large-scale subsurface structures
- Comprehensive surface seismic data coverage of the candidate storage site with sufficient resolution to "see" relevant features
- A suite of wellbore data from wells on or near the candidate storage site that includes
    - wireline log data
    - core material that is comprehensively analysed
    - well tests
    - some degree of seismic tie-in from these wellbores to the surface seismic data
- A credible and complete survey of all old wellbores on and near the candidate storage site that provides detail on the current state of each wellbore's cement

[1] Some CO2 will in some special situations react with in situ fluid and solid components to form minerals in the storage reservoir pore space, but this process will be too slow for the relevant time scale of mitigation of climate change.

[2] The vadose zone, also termed the unsaturated zone, is the portion of Earth between the land surface and the phreatic zone or zone of saturation ("vadose" is Latin for "shallow"). It extends from the top of the ground surface to the water table. Water in the vadose zone has a pressure head less than atmospheric pressure, and is retained by a combination of adhesion (funicular groundwater), and capillary action (capillary groundwater). If the vadose zone envelops soil, the water contained therein is termed soil moisture. Movement of water within the vadose zone is studied within soil physics and hydrology, particularly hydrogeology, and is of importance to agriculture, contaminant transport, and flood control (from http://www.wikipedia.org).

and casing sealing, including a soil gas flux history that covers several seasons of soil gas flux in the immediate vicinity of abandoned wellbores

- A sufficiently detailed history of previous underground activities at or near the site such as mining, disposal of wastes, storage of natural gas, storage of town gas, etc.

2.1 Mechanisms of Storage and the Multi-Barrier Concept

Four main storage mechanisms for CO_2 operate in reservoir rocks (Hitchon 1996). These may operate in combination in one or several parts of a site. These are:
1) Structural and stratigraphical trapping, where the migration of free (gas or dense phase) CO_2 in response to its buoyancy and/or pressure gradients within the reservoir is prevented by low permeability barriers (caprocks) such as layers of mudstone or halite.
2) *Residual saturation trapping*, in which capillary forces and adsorption onto the surfaces of mineral grains within the rock matrix immobilize a proportion of the injected CO_2 along its migration path.
3) *Dissolution trapping*, where injected CO_2 dissolves in the reservoir brine, after which it is no longer positively buoyant, but instead forms negatively buoyant saturated brine which sinks instead of rises.
***4) Mineral trapping*,** in which dissolved CO_2 reacts with the native pore fluid and the minerals making up the rock matrix of the reservoir, e. g. by precipitating it as carbonates. CO_2 is incorporated into the reaction products as solid carbonate minerals and aqueous complexes dissolved in the formation water (sometimes called "ionic trapping", because of the often predominant bicarbonate anions).
5) ***Adsorption on the surface of coal bed cleats***, in which the CO_2 molecules "stick" in a stabile state, often by replacing methane molecules, since coal has a generally higher affinity to stick to CO_2 molecules than CH4 molecules. Although this last mechanism is primarily of interest for enhanced coalbed methane projects, which are outside of the scope of this work, the process may in fact be important at aquifer or depleted hydrocarbon storage sites which have a coal layer above the primary storage reservoir that may act as an attenuating layer to upward movement of CO_2 that has migrated out of the primary storage reservoir. This is because it has been observed that when coal adsorbs CO_2, it swells in volume. In an underground formation swelling can cause a sharp drop in permeability, which not only restricts the flow of CO_2 into the formation but also impedes the recovery of displaced coalbed methane.

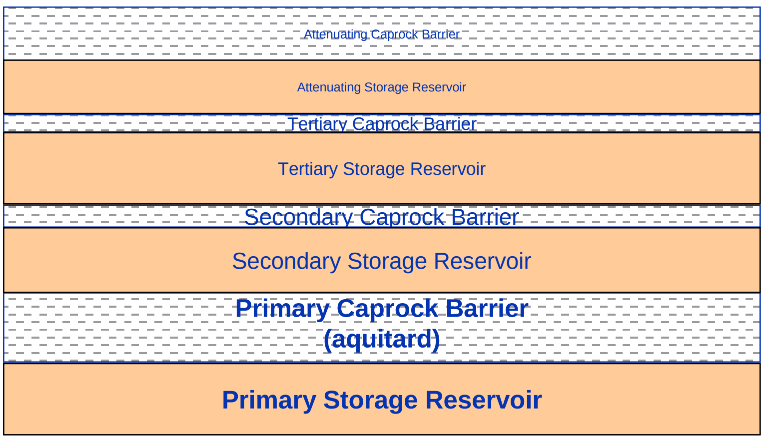

Fig. 2.1 *Concept of multibarrier protection*

Although a primary reservoir and its cap rock are often chosen for geologic storage, the presence of aquifers and aquitards above the primary aquifer and primary cap rock (=aquitard[3]) may contribute to effective storage performance in the long term. Thus one can refer to the primary, secondary, tertiary etc. attenuating storage reservoirs, and correspondingly, the primary, secondary, tertiary etc. caprock or barriers (Fig. 2.1).

This suggests that some escape from the primary storage reservoir may be allowable and in some special cases desirable because the CO_2 finds an even more secure place just above the primary storage reservoir, or is able to dissolve more quickly because it contacts a larger volume of aquifer brine than if it stays in the primary storage reservoir only. This can be extended to a tertiary aquifer and aquitard. Above this, movement of escaped CO_2 may be effectively attenuated and CO_2 eventually trapped as an immobile saturation, i.e. discrete gas bubbles essentially stuck in pore throats and cavities, incapable of forming a continuous, flowing phase. Thus long-term storage containment may be viewed in the context of a "multi-barrier" concept, which is quite different from expecting all stored CO_2 to stay in the primary storage reservoir as constrained by a single caprock barrier[4]. In all cases the engineered barrier of properly sealed and abandoned wellbores must also be in place and is probably a minimum requirement for long-term storage containment effectiveness.

The conclusion here is therefore that the entire geosphere including the primary storage reservoir and all aquifers and aquitards and their major structural features must be sufficiently mapped in order to assess the multi-barrier potential of a candidate storage site (Table 2.1).

Table 2.1 *Attributes and properties of various levels of containment of* **CO_2** *in the subsurface*

Characteristics	Attributes	Properties	Proxy for…
Potential for primary containment	Primary barrier or seal	Thickness Lithology Demonstrated sealing Lateral continuity	Likely sealing effectiveness Permeability, porosity Leakage potential Integrity and spill point
	Depth	Distance below surface	Density of CO_2 in reservoir

[3] An aquitard is a zone within the earth that restricts the flow of groundwater from one aquifer to another. An aquitard can sometimes, if completely impermeable, be called an aquiclude or aquifuge, e.g. a solid layer of NaCl (common salt). Aquitards are composed of layers of either clay or non-porous rock with low hydraulic conductivity

[4] This is in strong contrast to the USA Environmental Protection Agency program for protection of Underground Sources of Drinking Water, which essentially requires the geologic stored wastes do not migrate out of the primary storage reservoir for at least 10000 years.

Characteristics	Attributes	Properties	Proxy for…
	Reservoir	Lithology Permeability and porosity Thickness Fracture or primary porosity Pore fluid Pressure Tectonics Hydrology Deep wells Fault permeability	Likely storage effectiveness Injectivity, capacity Area extent of injected plume Migration potential Injectivity, displacement Capacity, tendency to fracture Induced fracturing, seismicity Transport by groundwater Likelihood of well pathways Likelihood of fault pathways
Potential for secondary containment	Secondary barrier or seal	Thickness Lithology Demonstrated sealing Lateral continuity Depth	Likely sealing effectiveness Permeability, porosity Leakage potential Integrity and spill point Density of CO_2
	Shallower barriers or seals	Thickness Lithology Lateral continuity Evidence of seepage	Likely sealing effectiveness Permeability, porosity Integrity and spill point Effectiveness of all seals
Attenuation Potential	Groundwater hydrology	Regional flow Pressure Geochemistry Salinity	Dispersion/dissolution Solubility Solubility Solubility
	Existing wells	Deep wells Shallow wells Abandoned wells	Direct pathway from depth Direct pathway Direct pathway, poorly known
	Faults	Tectonic faults Normal faults Strike-slip faults Fault permeability	Large permeable fault zones Seal short-circuiting Permeable fault zones Travel time
From Oldenburg (2005).			

The process of injecting CO_2 under pressure will increase reservoir pressure both locally and in a larger reservoir volume over time. This can

- Cause new fractures to be formed which might compromise the primary caprock barrier,
- Cause existing fractures and faults to become conduits for flow when they otherwise would not be
- Cause the capillary entry pressure of the primary caprock barrier to be exceeded, allowing CO_2 to flow upward through the secondary storage reservoir as if the primary caprock were a porous and permeable reservoir rock.

Initial data collection efforts and modeling must also take these sources of leakage and seepage risk into consideration. This implies a much more detailed sampling, measurement and analysis of particularly the primary caprock barrier than what is common for oil and gas exploration.

The following sections briefly describe the main challenges and drivers related to site data collection for different types of storage reservoirs.

2.2 Petroleum reservoir

The sources of leakage and seepage risk in CO_2 geological storage are closely related to the buoyant nature of stored CO_2 relative to reservoir brine at reservoir pressure and temperature. The buoyant forces of CO_2 stored in either natural gas or oil reservoirs may be either neutral or negative, i.e. that CO_2 will not tend to rise to the top of the primary storage reservoir.

Natural gas has lower density than CO_2 at all reservoir conditions, and will therefore hinder buoyant movement of stored CO_2 in reservoirs with mobile natural gas saturations. Oil and CO_2 have similar densities at relevant reservoir conditions, and in some cases, CO_2 will have higher density than oil. For such cases, the risk of buoyancy-driven leakage and seepage will also be significantly reduced, as long as reservoir pressure remains below the critical levels that induce new fracture, open or activate existing fractures, or exceed the capillary entry pressure of the caprock.

Hydrocarbon reservoirs exist because they have a proven caprock and trap. Developed petroleum reservoirs are often very well mapped and understood due to the large amount of data collected while drilling wells, which can total tens or hundreds of wells for a mature field. This can be an excellent starting point for assessing CO_2 storage. However, some hydrocarbon reservoirs are significantly pressure depleted (by 10's or 100's of bar), which may compromise the original sealing capacity of the trap and caprock. This must be thoroughly accounted for in the storage assessment process.

Developed hydrocarbon reservoirs are typically data rich, and may have a variety of sources of data indicating fluid movements, reservoir architecture and potential for effective CO_2 storage.

The primary concern for developed oil and gas reservoirs in the context of storing CO_2 is therefore the ability to properly seal existing wellbores on the site as some of them will be exposed to a relatively corrosive fluid under pressure in the reservoir over time due solely to the introduction of CO_2 into the reservoir.

2.3 Aquifers

If an aquifer is planned for CO_2 storage, it is critical that the primary caprock barrier properties be as thoroughly understood as possible, which means that the caprock must be cored and analysed comprehensively as part of the initial data collection process, before storage operations are approved at a particular candidate site. The caprock is almost never cored in petroleum reservoirs, where the very existence of hydrocarbons proves that the caprock seals effectively. In some sites it may also be desirable to core the secondary caprock barrier if it is believed to be an important part of the multi-barrier sealing concept of the site.

Faults penetrating the caprock must be mapped and evaluated. Also the geology laterally to the reservoir should be evaluated, particularly if the reservoir is an open type with poorly defined closures.

The search for petroleum reservoirs based on 2D and/or 3D seismic data supported by an exploration well, often leads to 'dry holes'. Such data may be of great value regarding potential CO_2 storage sites, as high porosity/permeability water reservoirs may be detected during the investigations. Although no additional exploration wells are drilled, the seismic coverage and the drilled exploration well will secure a fairly good documentation of the 'empty' reservoirs. Drill cuttings and various logs will indicate the thickness/quality of the caprock, and sonic log/check shots will supply data to image the reservoir boundaries.

Areas where exploration seismic surveys were performed but did not motivate exploration drilling may still provide interesting CO_2 storage candidates. Such sites must however perform further investigations including more detailed seismic surveys and exploratory drilling must be carried out to satisfy expectations of certainty of long-term storage containment effectiveness.

3. DISCRETE LEAK PATHS FROM UNDERGROUND STORAGE RESERVOIRS

Primary paths of escape of CO_2 from geological storage[5] are related to:

1) Fractures and faults, both natural, and those induced by injection operations
2) "Thief zones"
3) Leaky wellbores

The leak potential through such paths depends on:

a) Geometric dimensions of the fault, fracture, thief zone or wellbore, which may be functions of the stress state of the underground and therefore changes in reservoir pressure due to CO_2 injection
b) Rock characteristics with respect to porosity and permeability

The relative importance of these factors must be quantified. The approach to assessing the leak potential of a CO_2 storage reservoir is complementary to the approach used in petroleum exploration, where the main driving goal is to find reservoirs that have not leaked their trapped hydrocarbons, often by a process of elimination of identifying volumes of the geosphere that have clear “tell-tale” fingerprints of fluid migration.

Ligtenberg (2005) presents a method which is capable of enhancing patterns in the seismic data that are related to fluid migration by combining a set of advanced seismic attributes with neural network technology. By this method it is possible to highlight even very subtle fluid flow features that remain hidden when only single seismic attributes are used.

The most common direct hydrocarbon indicators on seismic data are bright spots, dim spots, flat spots, and phase changes (Allen and Peddy 1993). Similar seismic

[5] Secondary paths include diffusion through the primary caprock barrier, slow background hydrogeologic flow (e. g. lateral flow speeds of centimeters per year through an aquifer) that transports fluid out of the primary storage reservoir, … These are not treated in this document.

indicators should exist for liquid CO_2 and CO_2 gas bubbles. However, CO_2 gas in solution must be measured in situ.

Injected CO_2 may be subject to buoyancy and diapiric flow mechanism. This happens when a fluid with smaller specific gravity than water, e. g. liquid CO_2, migrate through a permeable and over-pressured formation towards a faults zone. At the fault zone, all other things being equal, the differences in viscosity and density between the hydrocarbon fluid and the formation water may cause the hydrocarbon fluid or liquid CO_2 to move upward in a diapiric manner, perhaps leading to focussed, buoyancy-driven pressure build-ups and may initiate or enhance local fracture development (Ligtenberg 2005). As an example, at the Sleipner field, the injected CO_2 has a temperature of 57 °C and a pressure of about 100 bars. The temperature in the Utsira Formation is 36 °C at the injection point (1012 m b.s.l.) and 29 °C at the reservoir top (800 m b.s.l.). But because of the great heat capacity of the Utsira Sandstone this will cool down the injected CO_2 and increase its density, and thus reduce the buoyancy forces. At Sleipner the specific gravity of the CO_2 plume is estimated to be roughly constant at 700 kg/m^3 (Chadwick et al. 2004a).

3.1 Fractures and faults

Methods for mapping possible leaking faults and fractures, at different scales, on land and offshore, prior to storage and during and after injection are listed in Table 3.1 and Table 3.2.

3.1.1 Identification of fractures and faults

If a depleted hydrocarbon field is targeted for CO_2 storage one can expect the cap rock to have good sealing qualities (otherwise there would have been no field in the first place). Detailed mapping of faults is essential if exploitation of hydrocarbons has caused differential compaction of the reservoir. This may have led to deformation of the cap rock, particularly along existing faults, but new faults and fractures may also have been created during production. Mapping of faults is essential if a low-pressure oil reservoir or a brine aquifer is targeted for CO_2 storage (Fig. 3.1 and Fig. 3.2).

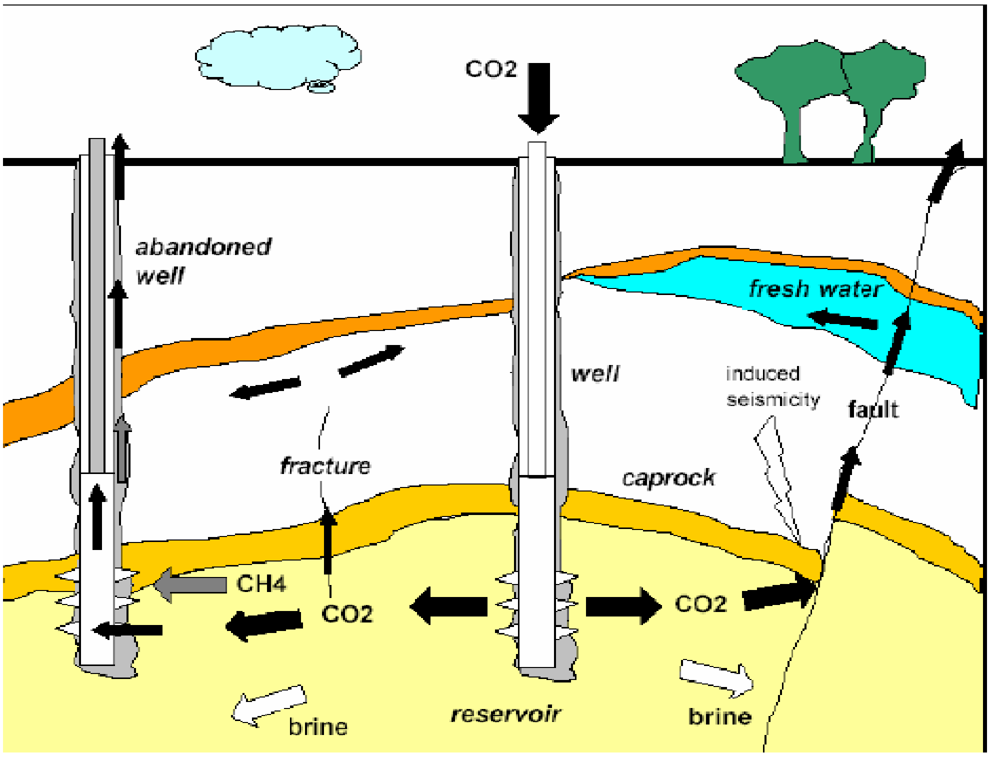

Fig. 3.1 *Illustration of potential* **CO_2** *leakage (seepage) pathways along fractures and faults cutting through the caprock and into a* **CO_2** *storage reservoir. From Damen et al. (2006).*

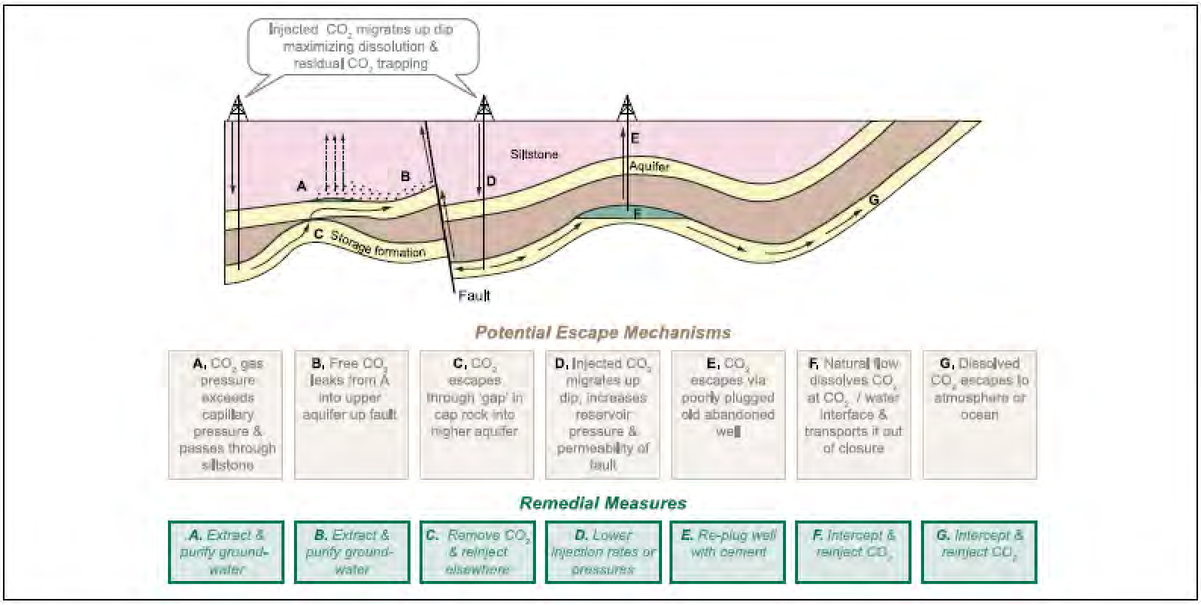

Fig. 3.2 *Some potential escape routes for* **CO_2** *injected into saline formations. From IPCC Special Report on Carbon dioxide Capture and Storage (IPCC 2005).*

The most relevant data is data collected from seismic surveys of a site, including 2D and 3D surface surveys (both acoustic sources and signal receivers on surface), or downhole seismic surveys involving either well-surface (vertical seismic profiling, VSP) or well-well (cross-hole) surveys. However, several other data sets and methods may also be considered, especially in order to identify fractures and faults on a more regional or detailed scale.

Injection of CO_2 may cause fracturing of a reservoir and its caprock if the pressure becomes too high. To avoid this, monitoring during injection should be carried out in one or more wells. Parameters that should be monitored are pressure, temperature, gas concentration, downhole fluid chemistry, tracers and pH. Also the application of cross-hole seismic, vertical seismic profiling, Borehole Televiewer®, Formation Micro-Scanner® and electromagnetic methods should be considered. The methods may provide indirect or direct evidence of fracturing.

A comprehensive list of investigation methods for identification of fractures and faults is given below.

- By field mapping on land
- By remote sensing of the land surface or seabed
- By potential field methods
- By electromagnetic methods
- By site-spesific methods for groundtruthing seabed fluid flow
- By 2D-seismic using visual inspection
- By 3D-seismic using visual inspection
- By 3D-seismic using automated pattern recognition
- By multicomponent seismic technology using visual inspection
- By downhole seismic using crosswell (well-well) seismic technology

- By downhole seismic using well-surface (vertical seismic profiling, VSP) technology
- By microseismicity
- By visual core inspection
- By visual inspection of wellbores using Formation Micro-Scanner and Borehole Televiewer
- By well measurments during injection

3.1.1.1 Field mapping on land

If CO_2 is to be stored in a reservoir below the land surface, the local and regional surface geology should to be mapped in great detail in the field. The mapping should include all geological units and unit boundaries as well as all faults and fractures. The mapping should include both bedrock geology and surficial sediments. All available surface and subsurface geological and geophysical information should be applied to compile a reliable model for the geological structure, stratigraphy and evolution of the area.

3.1.1.2 Remote sensing of the land or seabed surface

Remote sensing may be used to detect fault and fracture zones. In the broadest sense, remote sensing is large-scale acquisition of information of an object or phenomenon by the use of either recording or real-time sensing device(s) that is not in physical or intimate contact with the object, such as by way of airplane, satellite, spacecraft, buoy, ship, remotely operated vehicle (ROV) or automated operated vehicle (AOV).

There are two kinds of remote sensing. Passive sensors detect natural energy (radiation) that is emitted or reflected by the object or surrounding area being observed. Reflected sunlight is the most common source of radiation measured by passive sensors. Examples of passive remote sensors include film photography, infra-red, charge-coupled devices and radiometers. Active collection, on the other hand, emits energy in order to scan objects and areas whereupon a passive sensor then detects and measures the radiation that is reflected or backscattered from the target. RADAR is an example of active remote sensing where the time delay between emission and return is measured, establishing the location, height, speed and direction of an object (www.wikipedia.org).

Topography Faults may have a clear expression at the land surface due to differences in rock/sediment type or erosion resistance across the trace of fault planes. Similarly, fracture zones may be expressed as topographical lows due to low erosion resistance of the fractured bedrock. Fault and fracture zones may have a clear topographical expression on photographic and radar data collected from aircraft or satellite (e.g., www.eros.usgs.gov). Millimeter-scale topographic changes may be studied from Interferometrric Sattelite Radar (InSAR) data.

Bathymetry At the seabed, as on land, faults may have a clear expression due to differences in rock/sediment type or erosion resistance across the trace of fault planes, and fractured bedrock may be expressed as topographical lows due to low erosion resistance. Faults and fractures and features related to these (e.g. pockmarks) can be studied using multibeam echosounder, sidescan sonar, interferometric sonar or 3D seismic data.

<u>Multispectral and hyperspectral satellite data from land areas</u> Multispectral and hyperspectral data from various satellites can be obtained from, among others, the United States Geological Survey (USGS) (www.eros.usgs.gov). These data have a wide application, and may as an example be used to study variations in geochemistry and vegetation, which to a large degree reflect the local or regional geology (e.g. Fig. 3.3). Faults and fracture zones may be clearly visible. Examples of satellite products are ASTER, Landsat TM, Landsat ETM and Landsat MSS (www.eros.usgs.gov).

Fig. 3.3 *Example of Landsat 7 image showing a meteorite crater in Australia. From http://eros.usgs.gov/imagegallery*.

<u>Reflectivity of the seabed</u> Reflectivity (backscatter) of the seabed can be obtained from echosounder, sonar or 3D seismic data. Reflectivity is the amplitude of the signal reflected from the seabed. A hard bottom gives a stronger reflection than a soft

bottom. Faults can be detected because of differences in rock or sediment type across the trace of the fault. It is also possible to map patches of hard ground, which may indicate carbonate cemented seafloor due to leakage of hydrocarbons, which may occur along faults and fractures. Side scan sonar has commonly been used for site surveys in connection with hydrocarbon exploration wells. Side scan sonar data are acquired by forming a large sound beam on either side of the towfish. Time series data are sampled across these beams by summing all of the returns at any given time into one pixel. Some multibeam systems have emulated this data through digital beam forming, referring to the resultant image as "pseudo side-scan sonar". The multibeam echosounder collects a series of backscatter records across-track for each ping. These backscatter data are mosaicked on the terrain. The placing of imagery on terrain results in more accurate placement of the acoustic data. Amplitude data from the seabed can also be extracted from 3D seismic data (Fig. 3.4). This information can be used to map faults and fractures in the uppermost part of the seabed.

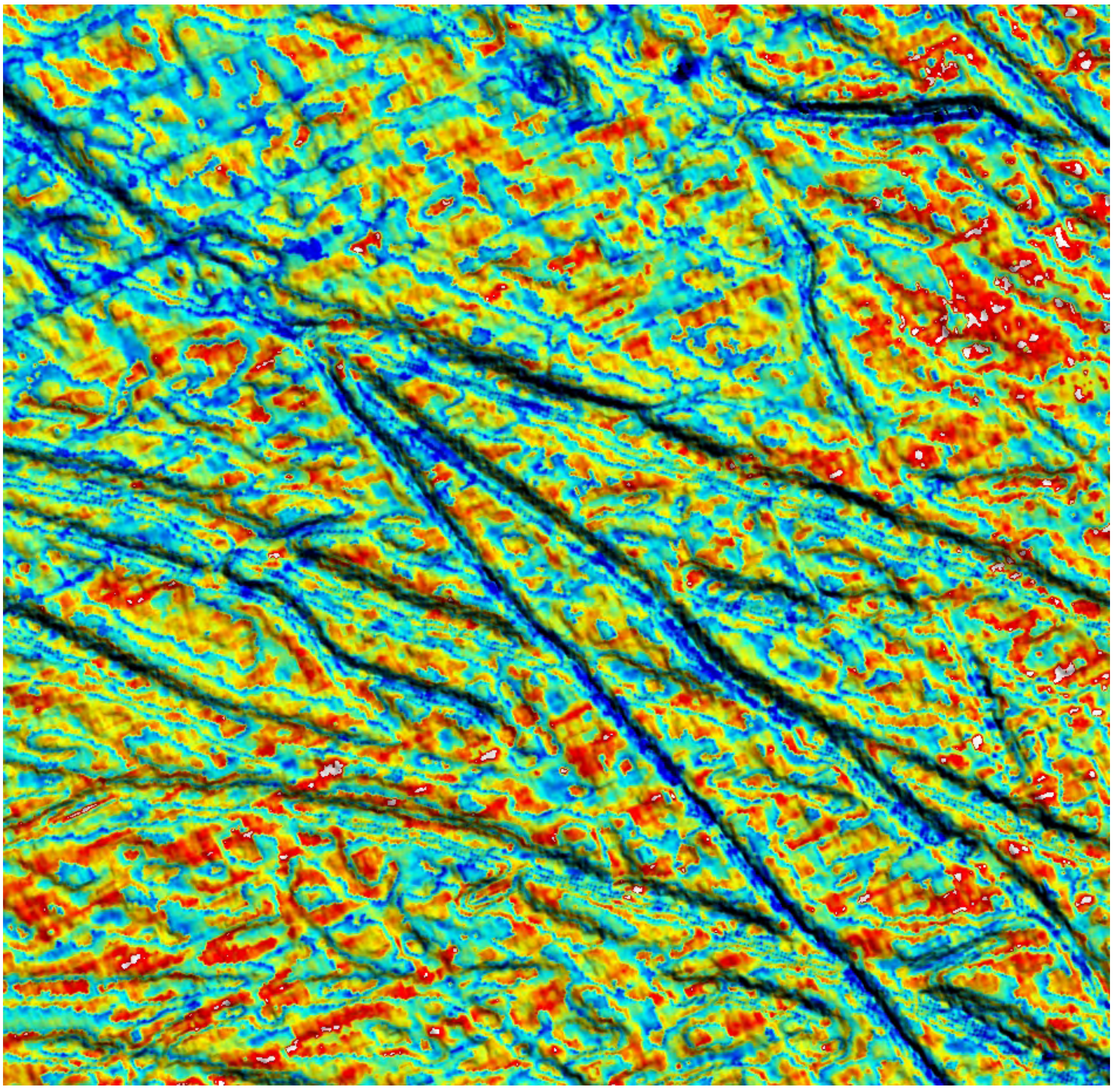

Fig. 3.4 *Example of seabed amplitude (red is high and blue is low) draped on top of bathymetry. 3D seismic data from the Barents Sea. Elongated furrows are iceberg plough marks, not fault lines (R.Bøe, NGU).*

3.1.1.3 Potential field methods

Magnetic data Magnetic data are used for for subsurface geological mapping both on land and at sea. Magnetic anomaly maps can be used for regional mapping, and major fault zones can be identified. Magnetic data cannot be used for detailed mapping of faults and fracture zones. Magnetic data can be obtained from both airborne and seaborne platforms.

Gravity data Gravity data is used for subsurface mapping and geological modelling both on land and at sea. Bouger gravity anomaly maps can be used for regional mapping, and major fault zones can be interpreted. Gravity data can not be used for detailed mapping of faults and fracture zones. Gavity data can be obtained from both airborne and seaborne platforms.

3.1.1.4 Electromagnetic methods

Controlled-source electromagnetics (CSEM) (www.westerngeco.com) will detect resistors often associated with hydrocarbon deposits in marine environments. It thus represents a significant advance in deepwater oilfield exploration. This technology may be applied to a wide variety of exploration targets from the near surface down to as deep as 4 km below the sea floor. The ability to predict reservoir fluid properties ahead of the drill bit means a considerable risk reduction for exploration programs and also a significant advantage while considering bids for offshore licenses.

A low-frequency electromagnetic field is transmitted using a deep-towed electric dipole antenna (source), and the resulting field is sampled at the seafloor. Unlike natural source plane-wave electrical methods such as magnetotellurics (MT), where thin, resistive layers are effectively transparent, the generated dipole field interacts with such a layer, allowing one to determine the layer's presence, thickness, and lateral extent. As with any geophysical method, there are limitations on the depth of burial, layer thickness, and resistivity contrasts that affect the viability of a target.

A high-power low-frequency dipole antenna is towed behind the survey vessel 50-100 meters above the seafloor. An array of ultrasensitive seafloor electromagnetic receivers is deployed in a pattern appropriate to the target. Transmitter and receivers are tracked and located acoustically. When data acquisition is complete, the receivers are recovered and the data are downloaded and analyzed. The data are then interpreted, first in terms of electrical units, and then as geologic formations, taking into account and integrating other geophysical data and the stratigraphy established for the region.

The primary application of marine CSEM is the identification and characterization of units that are more resistive than the surrounding rocks. Typically, a potential reservoir is identified with seismic data and CSEM used to analyze its resistivity, taking advantage of the resistivity contrast between oil- or gas-saturated rocks and those with a significant water content. The transformation from resistivity to geology, and finally pore fluid content, is an interpretive process that requires careful interpretation and integration of the CSEM data with seismic data and local well control. This method cannot be used for detailed mapping of faults and fractures.

Magnetotellurics (MT) (www.westerngeco.com) MT measures the natural low-frequency electromagnetic field of the earth. The field components measured on the seafloor are influenced by the resistivity of the geologic formations beneath the site, and the resistivity of the subsurface as a function of frequency can be computed from the EM field measurements. Resistivity as a function of depth and lateral position is obtained through inversion and modeling of the resistivity/frequency relationship. Geologic structure is then interpreted from an analysis of the resistivity data and its relationship to corresponding seismic data and well logs. As with any geophysical method, there are limitations on the depth of burial, formation thickness and resistivity contrasts that will affect the viability of an interpretation. The primary, difference (other than the location of the receiver site) between marine MT (MMT) and the more familiar land MT is that, in the marine environment, the higher frequencies are attenuated by the conductive sea water above electromagnetic receivers, limiting the high-frequency range and thus the minimum depth of investigation.

A self-contained MT station consisting of electric and magnetic field sensors and a data logging system is deployed on the seafloor from a suitable survey vessel. The marine MT station includes an anchor to hold it securely to the seafloor, an acoustic release mechanism to release the anchor, and a flotation device to bring the station to the surface. The receivers are tracked and located acoustically. The receivers are recovered and the data downloaded, processed, and interpreted in terms of, first electrical units, and then geologic formations and structure.

Resistivity is important because rock types significant in hydrocarbon exploration can be differentiated on the basis of their resistivity value. While MT cannot be used to detect oil directly, the identification of favorable rock types and the presence of geologic structures capable of trapping hydrocarbons are critical to successful exploration. Recent applications of marine MT have been in areas where seismic data are difficult to interpret or ambiguous due to presence of volcanics, carbonates, or salt. MMT can not be used for detailed mapping of faults and fractures.

3.1.1.5 Site-spesific methods for ground-truthing seabed fluid flow

Seabed fluid flow involves the flow of gases and liquids through the sea bed (Judd and Hovland 2007). Such fluids have been found to leak through the seabed into the marine environment in seas and oceans around the world - from the coasts to deep ocean trenches. This geological phenomenon has widespread implications for the sub-seabed, seabed, and marine environments. Seabed fluid flow affects seabed morphology, mineralization, and benthic ecology. Natural fluid emissions have a significant impact on the composition of the oceans and atmosphere, and gas hydrates and hydrothermal minerals are potential future resources (Hovland and Judd 1988). Various types of echosounders and sonars (e.g. side-scan sonar) may pick up gas bubbles in the water column (Fig. 3.5). Bubbles and active leakage from the seafloor may also be detected by video-inspection of the seabed (e.g. by ROV) or camera mounted on a frame. Indirect indicators of active seabed fluid flow or leaking hydrocarbons may be chemical compounds in seabed sediment samples. Methane-derived authigenic carbonate is a common phenomenon in many seep areas as well as cold-seep biological communities (Judd and Hovland 2007). Indirect indicators of seabed fluid flow may also be pockmarks, mud volcanoes and mud diapirs (see below). All these features may be related to leaking faults and fractures in the underground and require further detailed inspection.

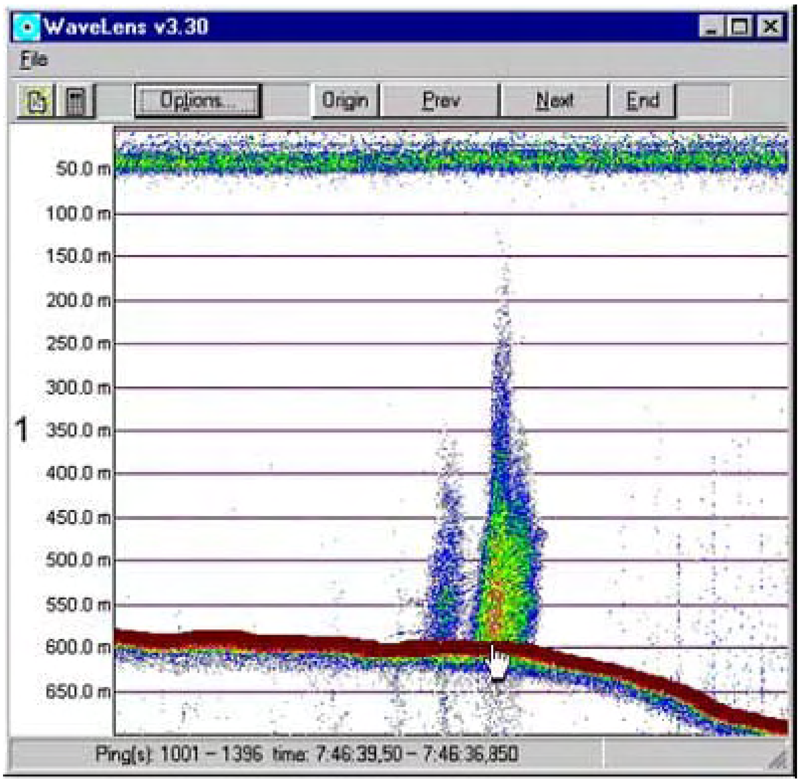

Fig. 3.5 *An echogram of a July 2001 double-seep (nicknamed "Two Captains") in the NW Black Sea. Data obtained with a SIMRAD EK-500 echosounder of the R/V "Professor Vodyanitskiy" at a depth of 593.5 m. The plume rises some 400 m into the water column (courtesy of V.N. Egorov /Yu. G. Artemov / S.B. Gulin, Sevastopol, Ukraine)*

3.1.1.6 2D-seismic using visual inspection

Seismic surveys remain the fundamental technology to seek out oil and gas reservoirs and to delineate detailed structures underground (Fig. 3.6). 2D-seismic data are important for interpretation of regional geology. Potential migration routes along strata and faults to shallow traps or to the seafloor can be mapped. Features indicating leakage may be detected, but the line spacing is often too large for detailed assessment. The technique is based on determinations of the time interval that elapses between the initiation of a seismic wave at a selected shop point and the arrival of reflected or refracted impulses at one or more seismic detectors.

In addition to conventional industry seismic, high-resolution boomer- or sparker-type data should be collected at the proposed storage site. Because of higher resolution, it may be possible to observe small-scale faults and other features in the upper part of the seabed.

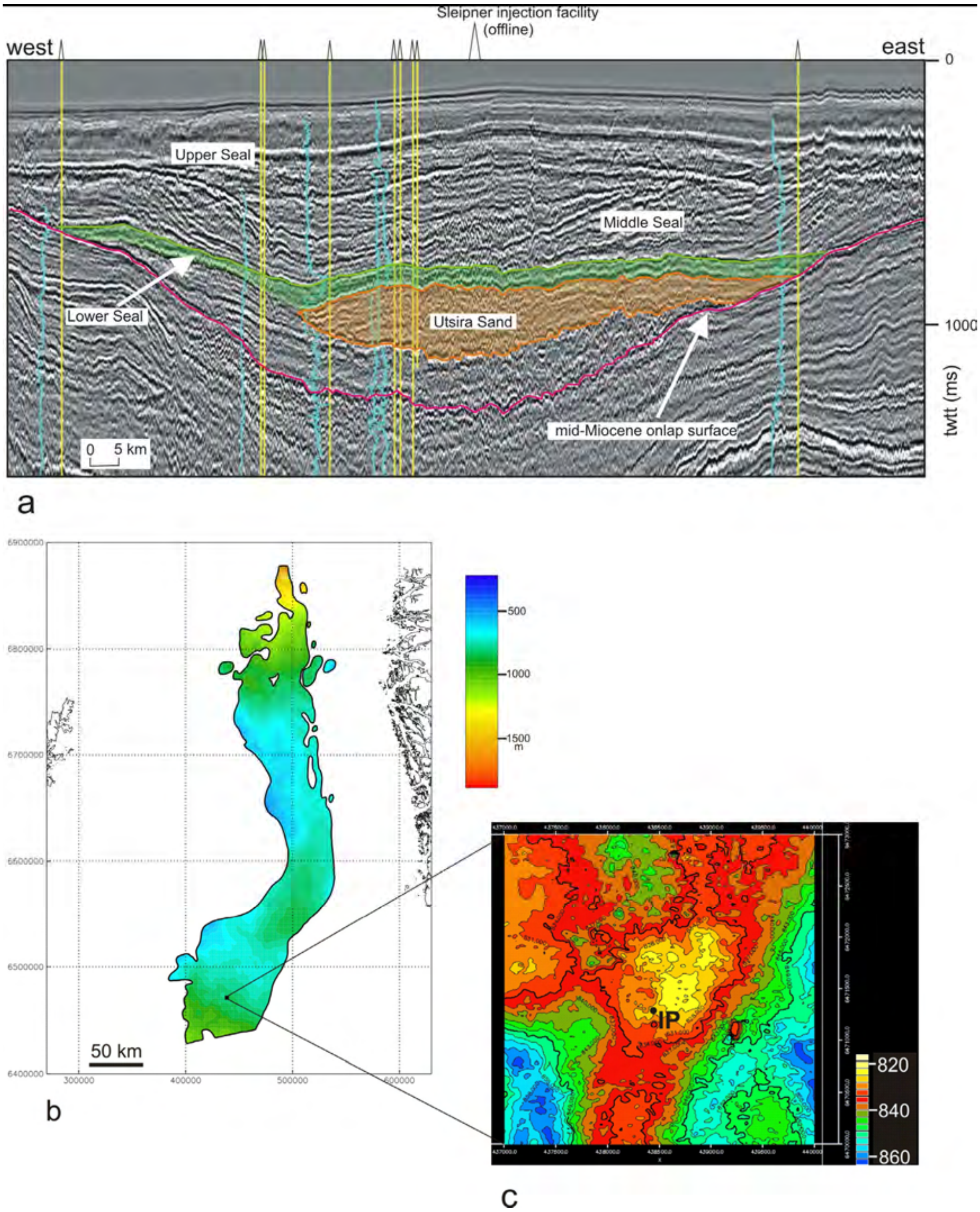

Fig. 3.6 *Sleipner seismic datasets a) Regional 2D seismic line through the Utsira Sand b) Depth map of the top of the Utsira Sand based on 2D regional seismic data c) Detailed contour map of the top of the Utsira Sand reservoir based on 3D seismc data. IP = Injection Point.(From Chadwick et al. 2006).*

3.1.1.7 3D-seismic using visual inspection

3D-seismic is by far the best and most efficient method to investigate subsurface strata and structures such as faults and fractures (Fig. 3.7). The data can be analyzed by using various seismic attributes, and even subtle features may be detected. 3D-seismic technology is applied to solve problems and reduce uncertainties across the entire range of exploration, development, and production operations. Surveys are used to characterize and model reservoirs, to plan and execute enhanced-oil-recovery strategies, and to monitor fluid movement in reservoirs (Fig. 3.8) as they are developed and produced. Marine seismic vessels used for 3D acquisition can tow many streamers simultaneously.

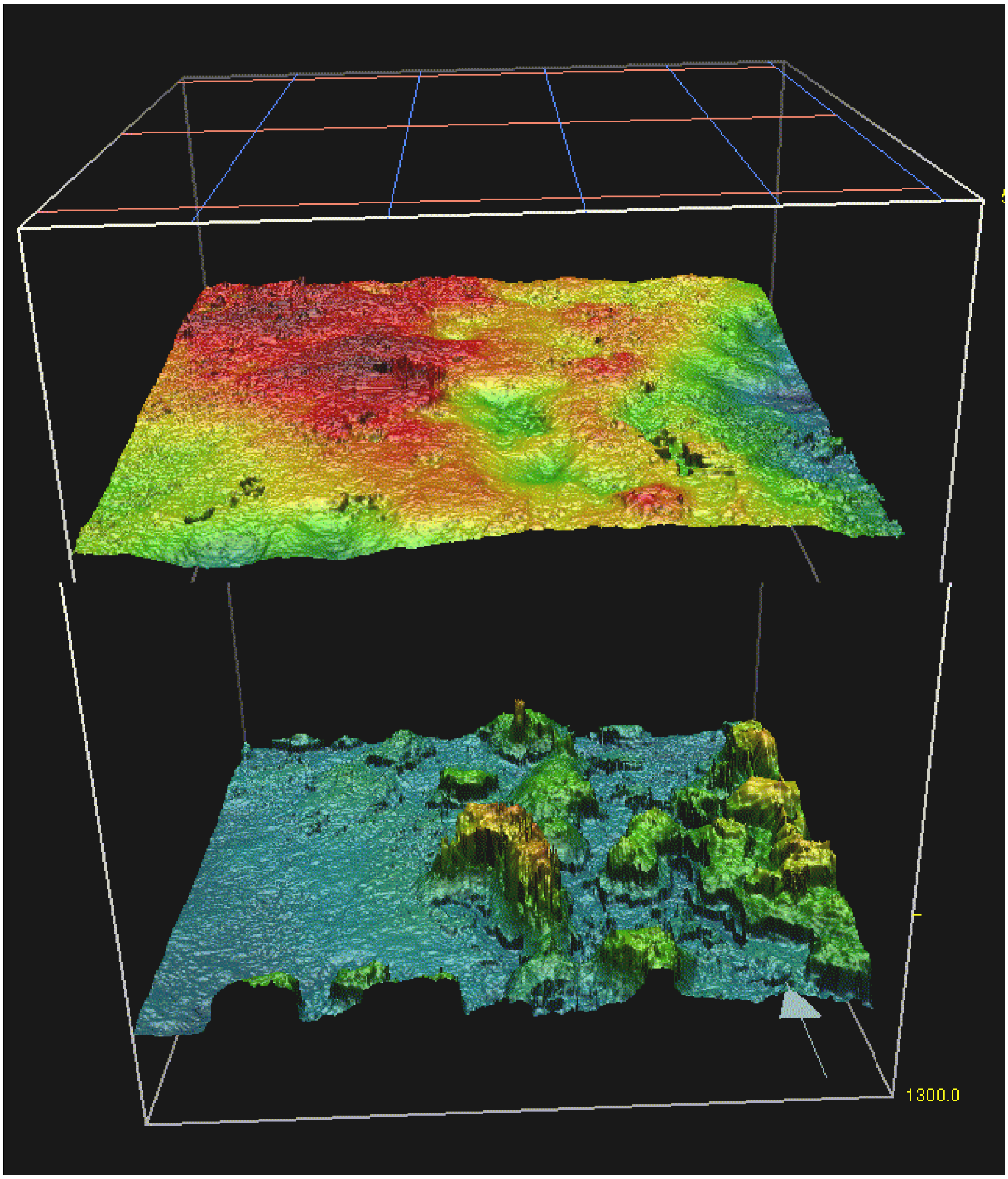

Fig. 3.7 *Perspective view of the top and base of the Utsira Sand around the injection point, based on 3D seismic. Note domal structure above the injection point. (Chadwick et al.(2006).*

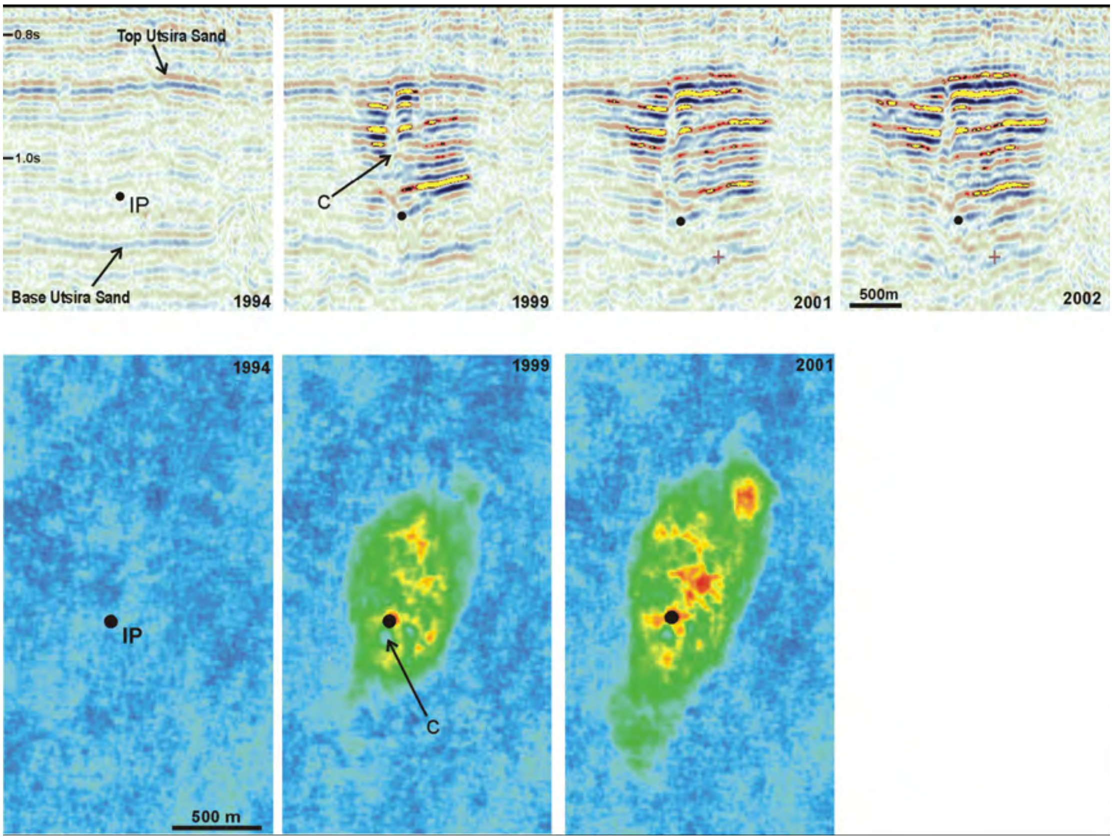

Fig. 3.8 *Sleipner time-lapse surface seismics 1994 to 2002. Seismic sections (inline) showing progressive development of plume reflectivity (top). Plume in plan view, showing integrated reflectivity (bottom). Note prominent low reflectivity vertical feature interpreted as primary feeder chimney (C). (Chadwick et al. 2006).*

Ocean-bottom-cable (OBC) acquisition comprises cables connected to stationary receiver stations deployed on the ocean bottom, and a marine vessel towing an array of air guns serves as the energy source. This makes it possible to survey congested areas safely and uniformly. In addition, resolution is higher because the quality of measurements is less affected by noise and other disruptions and because control of actual positioning makes repeated surveys more reliable.

3.1.1.8 3D-seismic using automated pattern recognition

A novel approach for identifying geological faults from high and medium quality 3D-seismic data using automated pattern recognition has recently been developed. The neural network algorithms that have been developed allow semi-automated identification, extraction, and modeling of small-scale fault surfaces imaged in 3D-seismic (Gibson et al. 2005, Fig. 3.9). Automatically detected faults have to be evaluated by the interpreter, and an iterative man-machine process must be introduced. Based on a multistage approach, the algorithm operates initially on a small spatial scale, identifying local discontinuities in the seismic horizons, and then gradually considers larger and larger segments of fault surfaces until a set of complete fault surfaces are identified. A large portion of the work involves merging of segments of fault surfaces, performed using a highest confidence first (HCF) stratagem, taking into consideration the context of the resultant fault geometry.

Recently, several seismic interpretation software companies have developed similar neural network algorithms for fault detection (e.g. Petrel®), and the methods represent a considerable improvement in the mapping of faults.

Evaluation of the conductivity of faults or fracture systems penetrating the cap rock may be difficult. Direct methods, which involve coring through the cap rock, or using packers/pressure tests across faults in exploration well, may not be conclusive. An indirect approach applying fault mapping and 'leakage feature' mapping from 3D data, is possibly the best approach (Ligtenberg 2005). The method involves using multiple seismic attributes and neural networks to enhance fluid migration pathways, including subtle features that are not detectable using single attributes only. The method may be used as a first estimate of fault seal or to calibrate results from other techniques. The results provide information about which faults and fault segments are sealing or leaking. Fluid flow along individual faults appears to be focused along zones of weakness, and fault seal research should thus be focused on finding such weak locations within fault zones, a task that is best done using 3D-seismic.

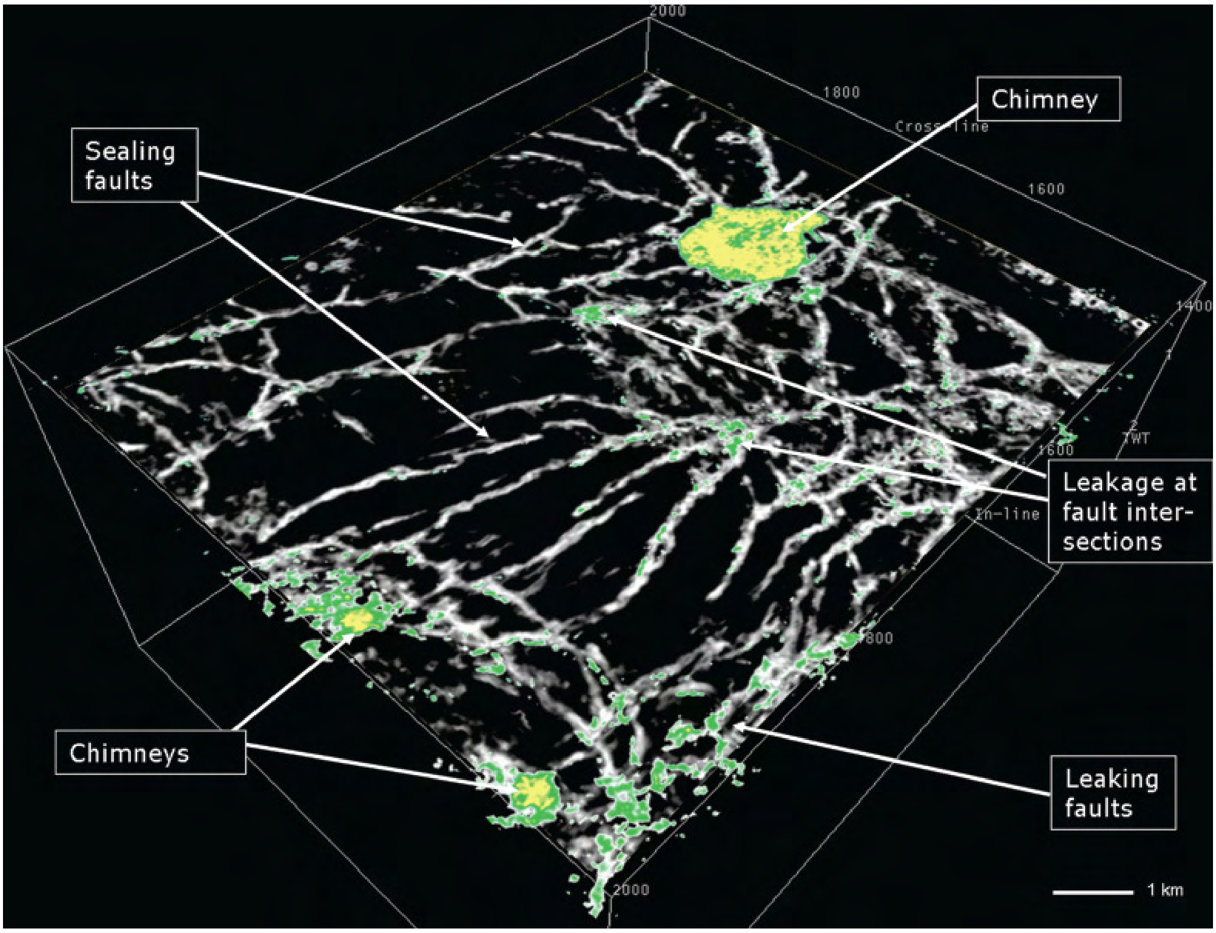

Fig. 3.9 *Time-slice through a fault cube (grey) with an overlay of elucidated fluid migration pathways in yellow-green ('chimney' probability shown, 0.7-1.0). The yellow zones correspond with large gas chimneys with high fluid flux. Increased fluid activity is observed at fault intersections and along several faults, indicating leakage. Faults without enhanced fluid activity are interpreted to be sealing or to have very low fluid flux. Data from West Africa (Ligtenberg 2005).*

3.1.1.9 Multicomponent seismic technology (www.westerngeco.com)

Multicomponent seismic has been demonstrated to be an effective technology for risk reduction in exploration and development. In an exploration setting multicomponent measurements offer improved imaging, direct hydrocarbon and lithology indication and multiple attenuation compared with conventional P-wave seismic. In a development setting multicomponent measurements facilitate improved reservoir illumination and characterization.

Conventional surface seismic surveys record only compressional, or P-waves. Multicomponent seismic surveys record both P-waves and shear, or S-waves by recording all components of the returning wave field. Each sensor within a multicomponent recording cable comprises three orthogonally oriented geophones for land acquisition, plus a hydrophone for marine acquisition (hence four-component or 4C). The P-waves are detected primarily by the Z-component geophone and the hydrophone, while S-waves are detected primarily by the X- and Y-component geophones.

Marine multicomponent acquisition operations typically consist of two or three vessels, one acting as a source vessel and the others as a cable deployment and recording vessels. A seabed recording cable is required because S-waves cannot travel through water. The source vessel generates P-waves. However, at every interface, S-waves are reflected as well as P-waves. These are often referred to as mode-converted S-waves, or PS-waves.

Multicomponent acquisition on land can utilize either conventional P-wave sources (dynamite or Vibroseis®) or S-wave sources, depending on the specific survey requirements.

Multicomponent seismic technology can be applied to many seismic and geological challenges, including mapping of fracture density (fracture porosity) and orientation (directions of preferred permeability) and gas seepages (Fig. 3.10).

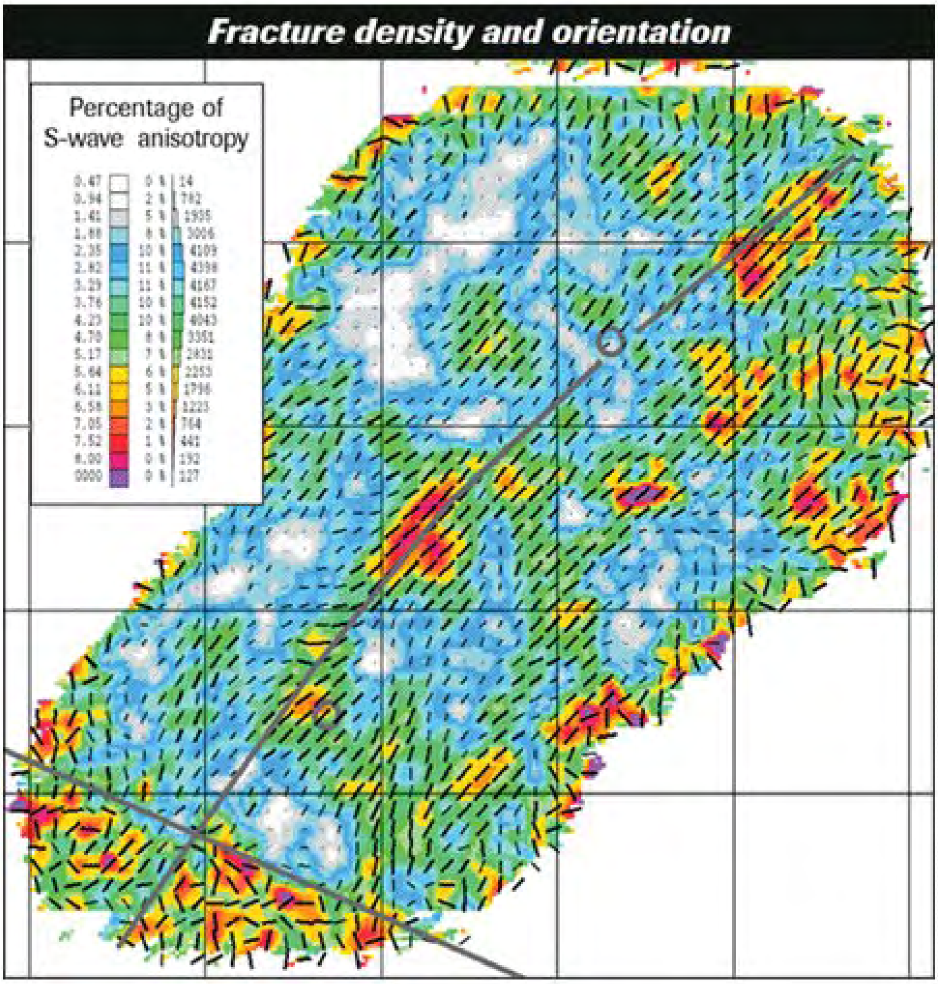

Fig. 3.10 *Fracture density and orientation mapped by multicomponent seismic technology (www.westerngeco.com).*

3.1.1.10 Downhole seismic using crosswell (well-well) seismic technology

Detailed understanding of reservoir flow and barrier architecture is crucial to optimizing hydrocarbon recovery. Crosswell seismology - that is, using seismic sources in a wellbore and recording the wave propagation in another well, is the only spatially continuous, very-high-resolution method that can image such features as faults, stratigraphic boundaries, unconformities, sequence porosity, fracturing, and additional untapped reservoir bodies away from the well. Crosswell data currently are expensive to acquire, and processing the data through topographic inversion and migration requires considerable expertise.

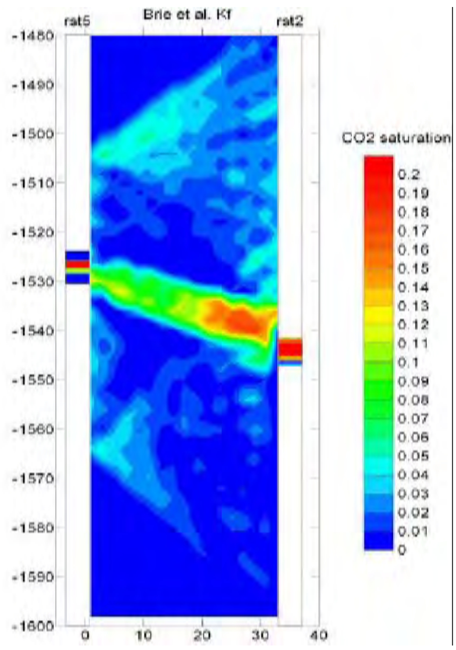

Fig. 3.11 *Example of crosswell seismic image. (Hoversten et al. 2001).*

3.1.1.11 Downhole seismic using well-surface technology

Vertical seismic profiling (VSP) has been a useful measurement to obtain rock properties (velocity, impedance, attenuation, anisotropy) in depth as well as to provide a seismic image of the subsurface. The VSP can also give insight into seismic wave propagation and provide processing and interpretive assistance in the analysis of surface seismic data. New multi-level receivers and hydrophone strings have improved the acquisition efficiency of the survey. Detailed interpretation, phase-matching work, amplitude variation with offset (AVO) efforts, and elastic-wave analysis can all benefit from VSP information. 3-D images from an area of sources recorded in a VSP show considerable promise. Similarly, the use of borehole seismic measurements to monitor hydraulic fracturing and perform repeated surveys is developing rapidly.

3.1.1.12 Mapping of microseismic activity

The mapping of microseismic activity constitutes a practical tool to determine the likely location of flow paths in the reservoir (Fig. 3.12). However, 3-D maps of microseismic activity define regions where pore pressure has become elevated and thus is hydraulically connected to the injection well. This does not necessarily imply that the microseismically-illuminated regions contain paths that support significant flow. That is, microseismic structures are not necessarily hydrologically significant structures.

The location of seismic events can be accomplished by observing an event on a string of geophones and modeling the arrival times with a forward model of all the travel paths. In that way, the source location can be determined from a match between model and measurement. In addition, the phase information on the triaxial geophones can be used to determine the direction from which the waves came. Using both P- and S-waves yields additional information on the source location in the inversion.

The generation of microseismicity can be explained by the shearing of existing joints when the pore is increased until the normal stress is reduced to zero causing the joint to fail. Although the generation of microseismicity can only be associated with pressure increase in joints, there are ample observations that indicate that flow channels do exist within the seismic clouds. Microseismicity can be regarded as the result of a disturbance in the equilibrium of mechanical forces by the energy input in this system. Some of the input strain energy is absorbed and stored by the elastic readjustment of rock mass and some will be released as a seismic energy. The implication of this is that the large volume one injects, the more strain energy is imposed on the rock mass and thus increasing the possibility of larger events (Baria et al. 2006).

Microseismic events are considered to be generated as follows: 1) hydraulic stimulation drives pressure propagation through a fracture network, 2) then the pore pressure in pre-existing fractures is increased, 3) the additional pressure leads to reduced friction between the fracture planes, 4) shear slip occurs on the fractures, 5) slip generates elastic waves to be observed as microseismic events.

The seismicity is dependent on injection rate and volume. An increase of the flow-rate induces an increase in number and often in magnitude of the seismic events. Furthermore, a larger proportion of larger magnitude events is observed after shutting in, although this does not lead to an increase of the number of events. This is probably related to the variation of the physical properties inside the fault zones and in the surrounding rocks, which are due to fluid circulation, pressure variations, thermal effects and geochemical processes during fluid/rock interactions. This assumption is especially true in the vicinity of the injection well, where pressure effects are strongest. The location of microseismic events seems to be closely related to geological and tectonic setting.

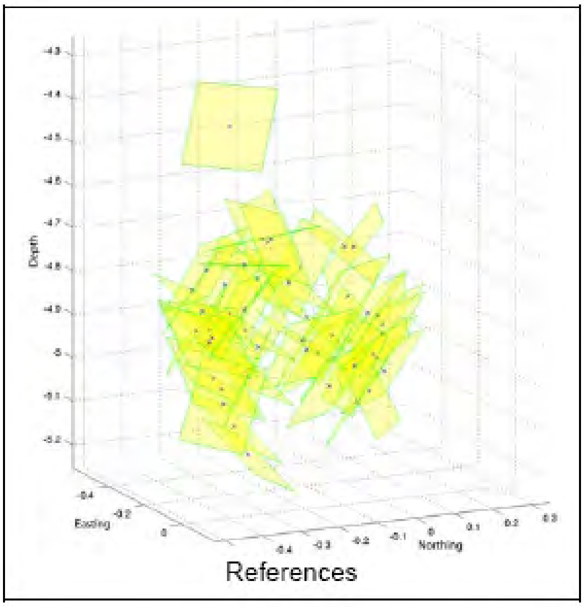

Fig. 3.12 *3D representation of fracture network from microseismicity (Cuenot et al. 2006).*

3.1.1.13 Visual inspection of cores

A minimum of one borehole should be drilled at the storage site to document the properties of the planned storage reservoir and its caprock. The borehole can in most cases be the planned injection well. Cores should be obtained from critical stratigraphic levels both in the caprock and the reservoir. The cores should be tested for geotechnical and physical properties as well as lithology, mineralogy and structurs, such as faults and fractures.

3.1.1.14 Formation Micro-Scanner (FMS) and Borehole Televiewer (BHTV)

Electrical (FMS) and acoustic image logging (BHTV) tools provide an invaluable opportunity to characterize the fracture populations that may control fluid flow in geothermal systems and oil and gas reservoirs (Fig. 3.13). However, these tools detect fractures by measuring different properties of the borehole wall. Fractures interpreted from electrical image logs are identified by contrasts in conductivity between the fracture and the adjacent borehole wall. By contrast, fractures in acoustic image logs are associated with changes in borehole wall surface roughness or acoustic reflectivity. In both types of logs, fractures with the largest apparent apertures are often, but not always, observed to dominate subsurface fluid flow in geothermal fields (Barton et al., 1998). Similarly, other properties affecting subsurface permeability such as rock type variation, foliation, and potential hydrothermal alteration can also be detected through these methods (Davatzes and Hickman 2005).

Electrical image logs appear to be sensitive to variations in mineralogy, porosity, and fluid content that highlight both natural fractures and rock fabrics. These fabric elements account for about 50% of the total population of planar structures seen in the electrical image log, but locally approach 100%. This fabric is unlikely to contribute to permeability in the reservoir. Acoustic image logs reveal a similar natural fracture population, but generally image slightly fewer fractures, and do not reveal rock fabric. Both logs also record textural properties of deformed materials within fractures; these textures can be related to variations in mineralogy, alteration, or porosity using the electrical log and can be used to infer slip history. In addition, locations of high fracture density occur adjacent to major faults, but also occur as zones confined within intervals of distinct rock type (Davatzes and Hickman 2005).

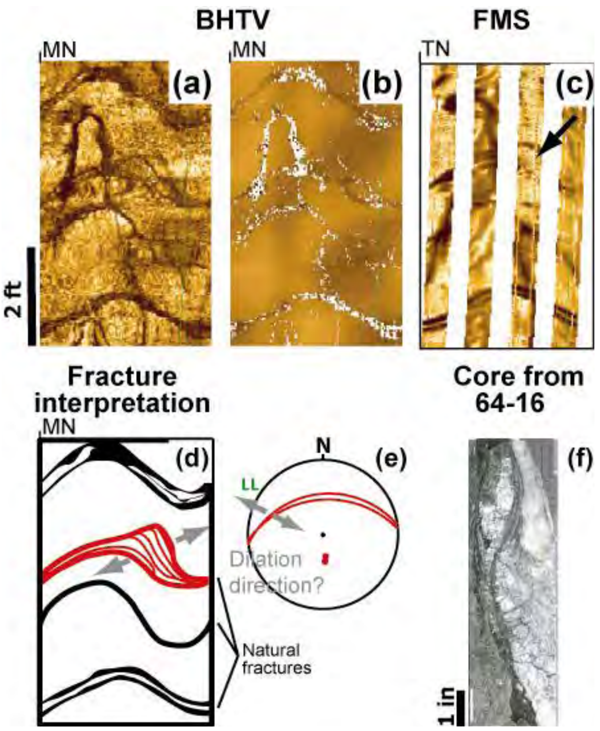

Fig. 3.13 *Example of BHTV and FMS data. (Davatzes and Hickman 2005).*

3.1.2 Features indicating fluid migration and subsurface leakage

Hydrocarbon leakage can often be recognized on seismic data and seafloor images, because it causes an acoustic, mechanical or diagenetic change in the geological sequences. Direct indications for fluid migration and seepage are expressed in characteristic seepage features both at the seabed and in the subsurface (Hovland & Judd 1988, Judd and Hovland 2007). Expressions of fluid seepage at the seabed comprise features such as carbonate mounds, mud volcanoes and pockmarks that are often associated with hydrocarbon gas migration. Dedicated seabed imagery or a good seabed reflection is necessary in order to study these features in detail. The subsurface contains different types of features that are direct and indirect indicators of fluid migration in general and hydrocarbon migration in particular. These include features such as gas chimneys, mud diapirs, bright spots, acoustic turbidity zones and palaeo-surface expressions, such as buried mud volcanoes and pockmarks (e.g. Hovland and Judd 1988).

3.1.2.1 Mud volcanoes

Mud volcanoes are distinctive, conical, topographic structures and are therefore easily recognized in seismic data high-resolution seafloor images (Fig. 3.14). Buried mud volcanoes separated by intervals of non-extruded sediments furthermore indicate that fluid expulsion has been episodic (Heggland 1998). Mud volcanoes are often, but not always, formed in association with release of gas from beneath the seabed. Mud volcanoes are encountered both onshore and offshore and have a wide variety of sizes, ranging from a few meters to several kilometres in basal diameter and up to 500 m in height (Hovland and Judd 1988). In contrast to pockmarks, that only record fluid expulsion (Hovland and Judd 1988, Cooper 2001), mud volcanoes are related to high fluid and sediment flux. Mud volcanoes are often associated with deeply buried, overpressured shales or areas of tectonic compression where they are aligned along structural features such as faults or fold axes (Hovland and Judd 1988). Mud volcanoes are often found in basins with rapid subsidence and high sedimentation rates.

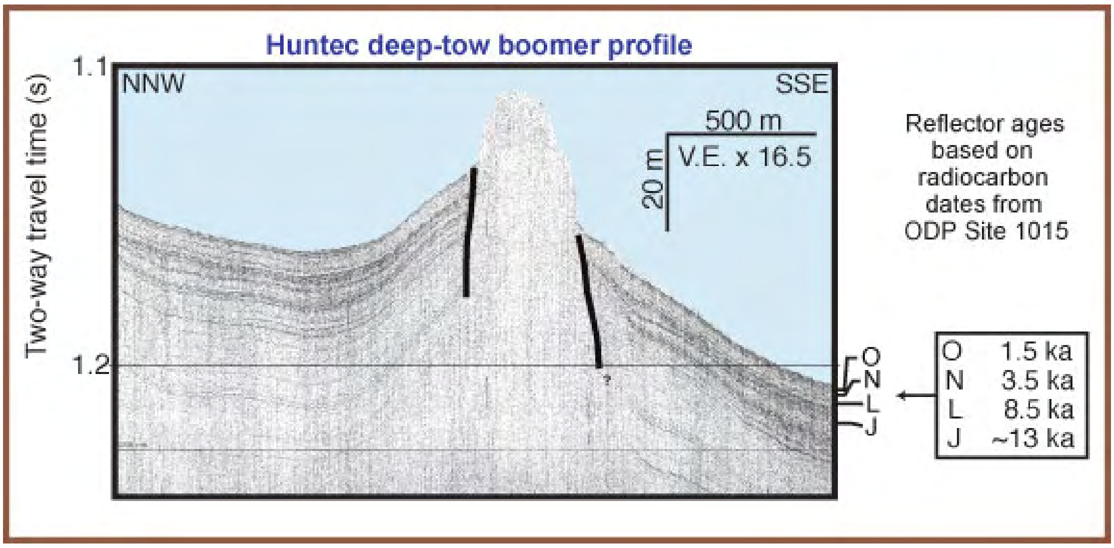

Fig. 3.14 *Example of a mud volcano at the seabed (Hein et al. 2006a and 2006b).*

3.1.2.2 Pockmarks

Pockmarks are crater-like depressions on the seabed that are related to focused fluid flow and are generally found in low permeability, fine-grained sediments (Fig. 3.15). They vary in size from 1 to 700 meters in diameter and from 0.5 to 45 m in depth (Hovland and Judd 1988, Cole et al. 2000). Internally, bacterial mats and/or carbonate crusts can be encountered, as well as carbonate cemented sediments. These are assumed to be formed by the oxidation of biogenic or mixed biogenic/thermogenic methane gas (Hovland and Judd 1988). On seismic data, when the water is deep enough to allow good seismic reflection from the seabed, and if the pockmarks are large enough (i.e. 50 m across or more), the pockmark craters can be clearly distinguished on the seabed reflection. They often occur in characteristic patterns. Normal pockmarks can be found along fault trends, which is a clear indication of fault leakage (Rise et al. 1999, Ligtenberg 2005). Pockmark groups can also be found in circular to semi-circular patterns, which is related to diagenesis and cementation of sediments into impermeable rocks directly above the fluid flow (Ligtenberg 2005).

They can also be found above crests of subcropping rocks, indicating up-dip fluid leakage along permeable bedrock strata (Rise et al. 1999). In addition, buried palaeo-pockmarks are clearly distinguishable on seismic data and are useful indicators of fluid flow in the past and of the possible presence of hydrocarbons in the deeper subsurface (Heggland 1998).

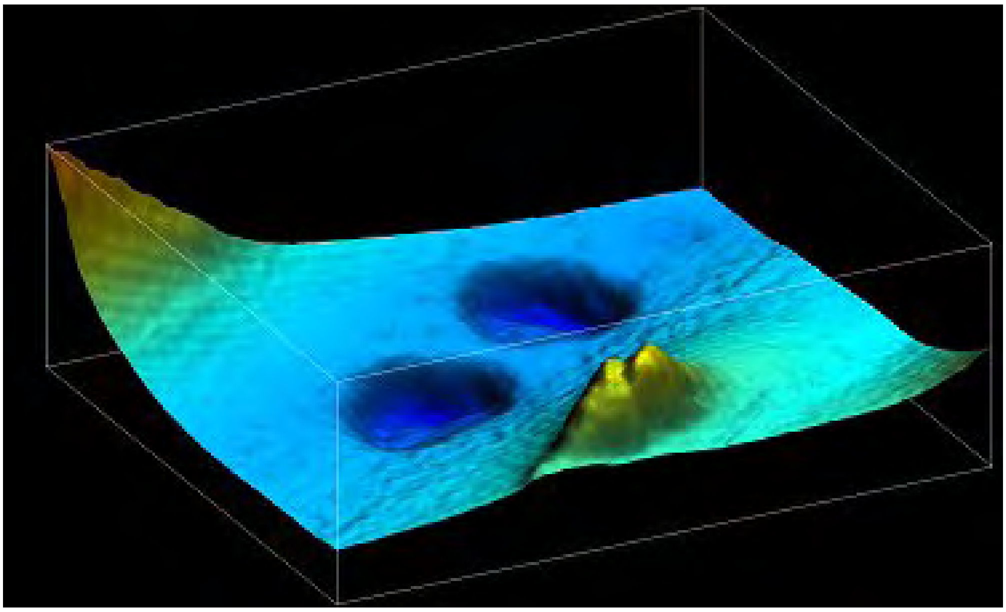

Fig. 3.15 *Pockmarks at the seabed of the Oslofjord. The pockmarks indicate leaking fluids from below. Source: Aivo Lepland, Geological Survey of Norway.*

3.1.2.3 Gas chimneys

Gas chimneys seen in seismic data are vertical to near-vertical columns of noisy seismic character, commonly interpreted as scattered energy caused by zones of focused fluid flow. In seismic data, gas chimneys are characterised by low trace-to-trace coherency, low reflection amplitudes and highly variable dip and azimuth of seismic reflections where they pass through the chimney (Ligtenberg 2005). They are normally assumed to represent high fluid flux paths that are initiated by an overpressure regime. Hydrocarbons are often implicated in their formation, but gas chimneys may also form because of pore water expulsion. Gas chimneys may feed mud volcanoes or pockmarks at the seabed, or they may charge shallow gas zones. In several basins worldwide it has proven crucial to map gas chimneys in order to avoid drilling hazards. Mapping gas chimneys are also used in petroleum exploration as an indicator for an active hydrocarbon system (Heggland et al. 2000).

3.1.2.4 Acoustic turbidity zones

Acoustic turbidity zones are areas of chaotic seismic reflections that are related to the presence of fluids within the sediments, commonly gas in solution, causing scattering and absorption of the acoustic energy. In many cases, reflections show a ‘pull-down effect’ when entering this acoustic turbidity zone (Hovland and Judd 1988). Acoustic turbidity zones occur in many basins worldwide, but are often overlooked and ignored as being some kind of seismic acquisition or processing artefact. However, in some cases a direct link with hydrocarbons is obvious (Ligtenberg 2005).

The occurrence of shallow gas in the succession above and adjacent to the reservoir should be carefully assessed. Shallow gas represents commonly pockets of gas trapped fairly close to the surface or sea floor. On seismic data shallow gas is commonly seen as high amplitude reflections, sometimes with clear phase reversals, or as acoustically disturbed zones. Possible lateral migration routes for this gas should be evaluated, as this gas may originally have migrated from a reservoir via faults.

3.1.2.5 Direct hydrocarbon indicators

The most common direct hydrocarbon indicators on seismic data are bright spots, dim spots, flat spots and phase changes (Allen and Peddy 1993).The most obvious and useful type in the described methodology is the bright spot. Bright spots are defined as being high amplitude, negative phase anomalies that are related to a decrease in density/acoustic velocity, caused by a change in fluids in the rocks. Within hydrocarbon accumulations, a strong decrease in acoustic impedance is expected at the top, because of the transition from brine to hydrocarbons. On seismic data, these bright spots commonly occur as local, high amplitude zones near leaking faults (Ligtenberg 2005), within reservoirs, above leaking reservoirs, at shallow gas pockets and along gas chimneys.

3.1.2.6 Hydrocarbon-related diagenetic zones (HRDZ)

A different type of high amplitude reflection with positive phase is the hydrocarbon-related diagenetic zone (HRDZ) (O'Brien et al. 1999), indicating hydrocarbon migration. HRDZs form when hydrocarbons leak from deeper reservoirs, migrate upward, charge shallower sand formations and finally biodegrade. Biological oxidation of the hydrocarbons produces localised, intense carbonate cementation. This cementation produces suffcient increase in acoustic impedance for a strong seismic response (O'Brien et al. 1999). HRDZs are often related to fault leakage and have linear expressions, but can also be related to point leakage, e.g. at fault intersections, forming circular anomalies.

Table 3.1 *Methods for mapping possible leaking faults and fractures at different scales on land and offshore prior to storage.*

Scale/ Method	*Regional scale mapping on land*	*Regional scale mapping offshore*	*Aquifer scale mapping on land*	*Aquifer scale mapping offshore*	*Storage site mapping on land*	*Storage site mapping offshore*	*Cap rock inspection*
Field mapping	Field mapping	-	field mapping	-	Field mapping	-	Field mapping if outcrop
Remote sensing of land surface/ seabed	Topography, spectral data	Bathymetry	Topography, spectral data	Bathymetry, reflectivity	Topography, spectral data	Batymetry, reflectivity	-
Ground-thruthing seabed fluid flow	-	-	-	Gas bubbles in water column, sediment geochemistry	-	Gas bubbles in water column, sediment geochemistry	-
Potential field methods	Magnetic and gravity anomaly	Magnetic and gravity anomaly	-	-	-	-	-
Electromagntic methods	-	-	-	-	-	-	-
2D-seismic	Visual inspection	Visual inspection	Visual inspection	Visual inspection	Visual inspection	Visual inspection	-
3D-seismic	-	-	-	-	Visual inspection	Visual inspection	-
3D-seismic automated pattern recognition	-	-	-	-	Automated interpretation	Automated interpretation	-
Multicomponent seismic technology	-	-	-	-	Visual inspection	Visual inspection	-

Scale/ Method	*Regional scale mapping on land*	*Regional scale mapping offshore*	*Aquifer scale mapping on land*	*Aquifer scale mapping offshore*	*Storage site mapping on land*	*Storage site mapping offshore*	*Cap rock inspection*
Crosswell seismic	-	-	-	-	Visual inspection	Visual inspection	-
Well-well seismic	-	-	-	-	Visual inspection	Visual inspection	-
Microseismicity	-	-	-	-	Measurements	Measurements	-
Core inspection	-	-	-	-	Visual inspection	Visual inspection	Visual inspection
Video inspection of wellbores	-	-	-	-	Visual inspection	Visual inspection	Visual inspection
FMS and BHT	-	-	-	-	Automated interpretation	Automated interpretation	Automated interpretation

Table 3.2 *Methods for monitoring possible leaking faults and fractures during and after injection.*

Scale/ Method	*Regional scale mapping on land*	*Regional scale mapping offshore*	*Aquifer scale mapping on land*	*Aquifer scale mapping offshore*	*Storage site mapping on land*	*Storage site mapping offshore*	*Cap rock inspection*
Field mapping	-	-	-	-	Field mapping	-	-
Remote sensing of land surface/ seabed	-	-	-	-	Topography	Bathymetry	-
Ground-thruthing seabed fluid flow	-	-	-	-	Gas flux, gechemical or biological changes at the ground	Gas bubbles in water column, gechemical or biological changes at seabed	-
Potential field methods	-	-	-	-	Gravity	Gravity	-
Electromagntic methods	-	-	-	-	-	-	-
2D-seismic	-	-	-	-	Visual inspection	Visual inspection	-
3D-seismic	-	-	-	-	Visual inspection	Visual inspection	-
3D-seismic automated pattern recognition	-	-	-	-	Automated interpretation	Automated interpretation	-
Multicomponent seismic	-	-	-	-	Visual inspection	Visual inspection	-

Scale/ Method	*Regional scale mapping on land*	*Regional scale mapping offshore*	*Aquifer scale mapping on land*	*Aquifer scale mapping offshore*	*Storage site mapping on land*	*Storage site mapping offshore*	*Cap rock inspection*
technology							
Crosswell seismic	-	-	-	-	Visual inspection	Visual inspection	-
Well-well seismic	-	-	-	-	Visual inspection	Visual inspection	-
Microseismicity	-	-	-	-	Measurements	Measurements	-
Core inspection	-	-	-	-	-	-	-
Video inspection of wellbores	-	-	-	-	-	-	-
FMS and BHT	-	-	-	-	-	-	-

Table 3.3 *A selection of possible moniotoring tools for* CO_2 *storage. Note the tools suggested for leakage monitoring. From Chadwick et al. (2006).*

Onshore only — Offshore only — Onshore & Offshore

Primary use — Secondary use

Method			Tool	Setting	Deep	Shallow	Plume location/ migration	Fine scale processes	Leakage	Quantification
Seismic			3D/4D surface seismic	Onshore & Offshore	Primary	Secondary	Primary	Secondary	Secondary	Primary
Seismic			Time lapse 2D surface seismic	Onshore & Offshore	Primary		Primary	Secondary		
Seismic			Multicomponent seismic	Onshore & Offshore	Primary		Primary	Primary		
Seismic	Acoustic imaging		Boomer / Sparker	Offshore only		Primary	Secondary		Primary	
Seismic	Acoustic imaging		High resolution acoustic imaging	Offshore only		Primary	Secondary		Primary	
Seismic			Microseismic monitoring	Onshore & Offshore			Secondary			
Seismic	Well based		4D cross-hole seismic	Onshore & Offshore	Primary		Secondary	Primary		Secondary
Seismic	Well based		4D VSP	Onshore & Offshore	Primary		Secondary	Primary		
Sonar Bathymetry			Sidescan sonar	Offshore only		Primary			Primary	
Sonar Bathymetry			Multi beam echo sounding	Offshore only		Primary			Primary	
Gravimetry			Time lapse surface gravimetry	Onshore & Offshore	Primary		Secondary			Secondary
Gravimetry			Time lapse well gravimetry	Onshore & Offshore	Primary			Secondary		
Electric / Electro - magnetic			Surface EM	Onshore only	Secondary	Primary	Secondary		Secondary	
Electric / Electro - magnetic			Seabottom EM	Offshore only	Primary	Primary	Secondary			
Electric / Electro - magnetic			Cross-hole EM	Onshore & Offshore	Primary			Secondary		
Electric / Electro - magnetic			Permanent borehole EM	Onshore & Offshore	Primary			Secondary		
Electric / Electro - magnetic			Cross-hole ERT	Onshore & Offshore	Primary			Secondary		
Electric / Electro - magnetic			ESP	Onshore only	Primary	Secondary	Primary		Secondary	
Geochemical	*Fluids*	Down - hole / Springs	Downhole fluid chemistry	Onshore & Offshore	Primary	Primary		Secondary	Primary	Secondary
Geochemical	*Fluids*	Down - hole / Springs	PH measurements	Onshore & Offshore	Primary	Primary		Secondary	Primary	Secondary
Geochemical	*Fluids*	Down - hole / Springs	Tracers	Onshore & Offshore	Primary	Primary		Secondary	Primary	Secondary
Geochemical	*Fluids*	Marine	Seawater chemistry	Offshore only		Primary			Primary	Secondary
Geochemical	*Gasses*		Bubble stream chemistry	Offshore only		Primary			Primary	Secondary
Geochemical	*Gasses*	Atmos-phere	Short closed path (NDIRs & IR	Onshore & Offshore		Primary			Primary	Secondary
Geochemical	*Gasses*	Atmos-phere	Short open path (IR diode lasers)	Onshore & Offshore		Primary			Primary	Secondary
Geochemical	*Gasses*	Atmos-phere	Long open path (IR diode lasers)	Onshore & Offshore		Primary			Primary	Secondary
Geochemical	*Gasses*	Atmos-phere	Eddy covariance	Onshore & Offshore		Primary			Primary	Secondary
Geochemical	*Gasses*	Soil gas	Gas flux	Onshore only		Primary			Primary	Secondary
Geochemical	*Gasses*	Soil gas	Gas concentrations	Onshore only		Primary			Primary	Secondary
Ecosystems			Ecosystems studies	Onshore & Offshore		Primary			Primary	
Remote sensing			Airborne hyperspectral imaging	Onshore only		Primary			Primary	Secondary
Remote sensing			Satellite interferometry	Onshore only	Primary		Primary			
Remote sensing			Airborne EM	Onshore & Offshore		Primary			Primary	
Others			Geophysical logs	Onshore & Offshore	Primary			Primary		Secondary
Others			*Pressure / temperature*	Onshore & Offshore	Primary				Primary	Secondary
Others			*Tiltmeters*	Onshore & Offshore	Primary	Secondary	Secondary	Secondary		

Table 3.4 *Direct and indirect techniques that can be used to monitor* CO_2 *storage. From IPCC Special Report on Carbon dioxide Capture and Storage (IPCC 2005).*

Measurement technique	Measurement parameters	Example applications
Introduced and natural tracers	Travel time Partitioning of CO_2 into brine or oil Identification sources of CO_2	Tracing movement of CO_2 in the storage formation Quantifying solubility trapping Tracing leakage
Water composition	CO_2, HCO_3^-, CO_3^{2-} Major ions Trace elements Salinity	Quantifying solubility and mineral trapping Quantifying CO_2-water-rock interactions Detecting leakage into shallow groundwater aquifers
Subsurface pressure	Formation pressure Annulus pressure Groundwater aquifer pressure	Control of formation pressure below fracture gradient Wellbore and injection tubing condition Leakage out of the storage formation
Well logs	Brine salinity Sonic velocity CO_2 saturation	Tracking CO_2 movement in and above storage formation Tracking migration of brine into shallow aquifers Calibrating seismic velocities for 3D seismic surveys
Time-lapse 3D seismic imaging	P and S wave velocity Reflection horizons Seismic amplitude attenuation	Tracking CO_2 movement in and above storage formation
Vertical seismic profiling and crosswell seismic imaging	P and S wave velocity Reflection horizons Seismic amplitude attenuation	Detecting detailed distribution of CO_2 in the storage formation Detection leakage through faults and fractures
Passive seismic monitoring	Location, magnitude and source characteristics of seismic events	Development of microfractures in formation or caprock CO_2 migration pathways
Electrical and electromagnetic techniques	Formation conductivity Electromagnetic induction	Tracking movement of CO_2 in and above the storage formation Detecting migration of brine into shallow aquifers
Time-lapse gravity measurements	Density changes caused by fluid displacement	Detect CO_2 movement in or above storage formation CO_2 mass balance in the subsurface
Land surface deformation	Tilt Vertical and horizontal displacement using interferometry and GPS	Detect geomechanical effects on storage formation and caprock Locate CO_2 migration pathways
Visible and infrared imaging from satellite or planes	Hyperspectral imaging of land surface	Detect vegetative stress
CO_2 land surface flux monitoring using flux chambers or eddycovariance	CO_2 fluxes between the land surface and atmosphere	Detect, locate and quantify CO_2 releases
Soil gas sampling	Soil gas composition Isotopic analysis of CO_2	Detect elevated levels of CO_2 Identify source of elevated soil gas CO_2 Evaluate ecosystem impacts

3.1.3 Classification of fractures (joints and faults)

Fractures are structures resulting from brittle behaviour in which blocks of rocks are displaced relative to one another across narrow and approximately planar discontinuities. The discontinuities are called joints if the component of displacement parallel to the structure is zero (or too small to be apparent to the unaided eye) or faults if the parallel component of displacement is larger. Most joints and faults form by fracturing, that is, by development of cracks across which the original cohesion is lost (Hobbs et al. 1976, Hancock and Engelder 1989).

3.1.3.1 Joints

Joints usually occur as families of fractures with more or less regular spacing in a given rock type, and the joints in a set are often approximately parallel to another. The whole assemblage of joints present in a rock volume is called a joint system. Joints may have dimensions ranging from tens of centimetres to hundreds of metres and repeat distances of several centimetres to tens of metres (Fig. 3.16). Small, inconspicuous joints may be visible only in thin section under the microscope (microjoints/microfractures).

Joints associated with faults may predate the faults and have no genetic relation to the faults apart from a possible control on the orientation of the fault planes. Other joints may be intimately related to faulting and useful in revealing the sense of slip on the fault planes, e.g. feather joints or pinnate fractures. If a fracture forms with a shear component that is zero, the structure is an extension joint, otherwise it is a shear joint.

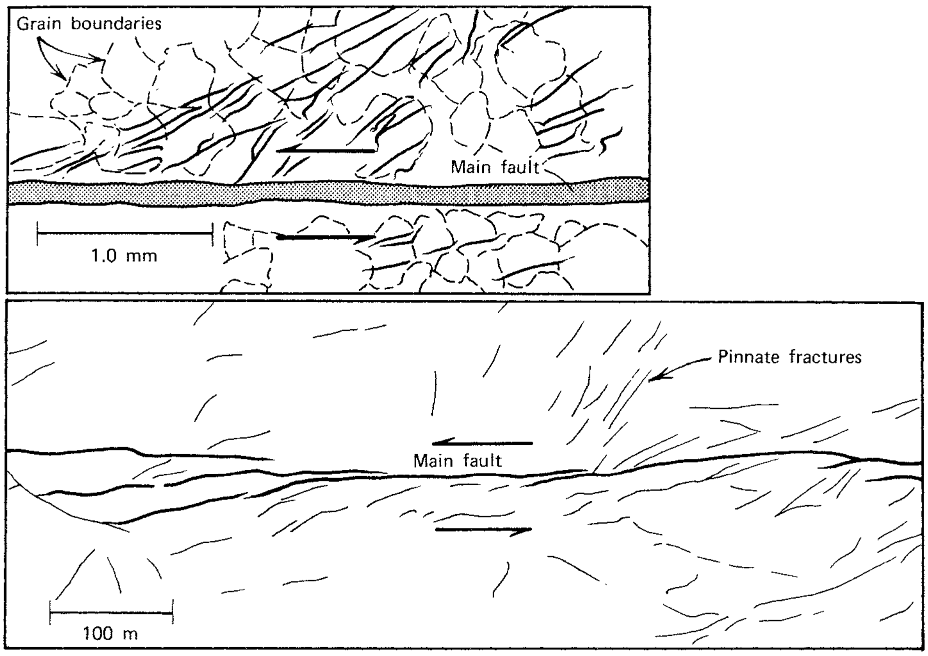

Fig. 3.16 *Two examples of pinnate fractures associated with faults. (Hobbs et al. 1976).*

3.1.3.2 Faults

Brittle deformation of rocks may lead to well-defined fracture planes or zones. A fault is a planar discontinuity between blocks of rocks that have displaced past one another in a direction parallel to the discontinuity. A fault zone is a tabular region containing many parallel or anastomosing faults. The relative motion that takes place across the fracture plane yields extension fractures or shear fractures. Shear fractures in rocks visible in outcrops or from aero- or satellite images are called faults. Larger faults are commonly structures of major tectonic importance. Smaller shear fractures at the scale of a millimetre or less and visible under the microscope, are called microfaults (Twiss and Moores 1992).

The three major types of faults are normal, reverse (a thrust fault is a low angle reverse fault) and strike-slip (wrench, transcurrent, Fig. 3.17 and Fig. 3.18). All of these can be related to straight dip slip or oblique dip slip along the fault plane between the hanging and the footwall blocks.

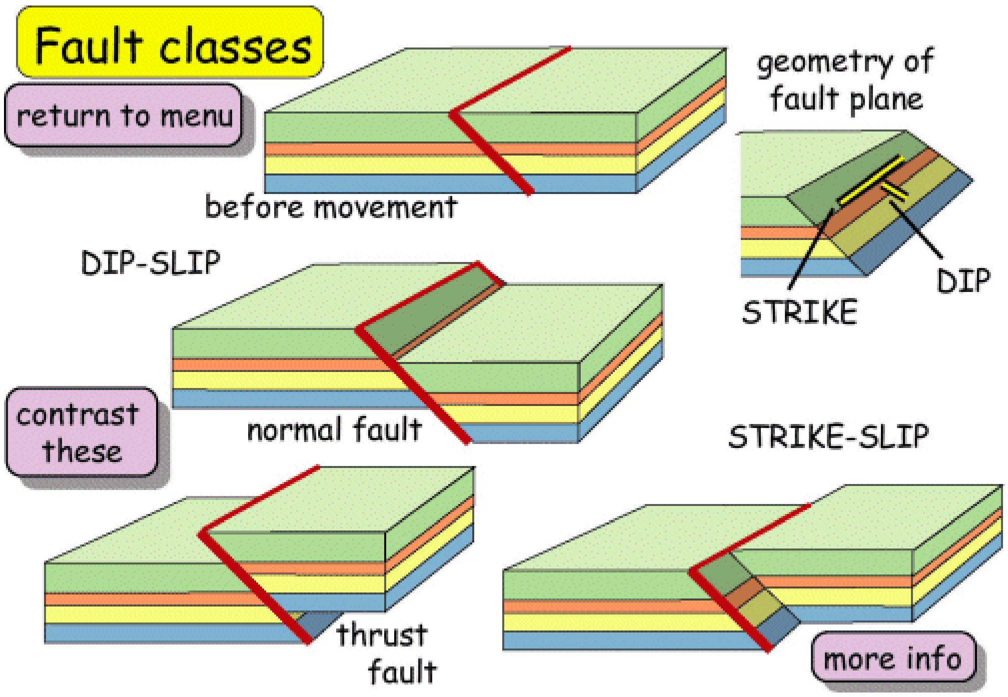

Fig. 3.17 *Classification of faults. From http://www.see.leeds.ac.uk/structure/faults/types/classes/classes.htm.*

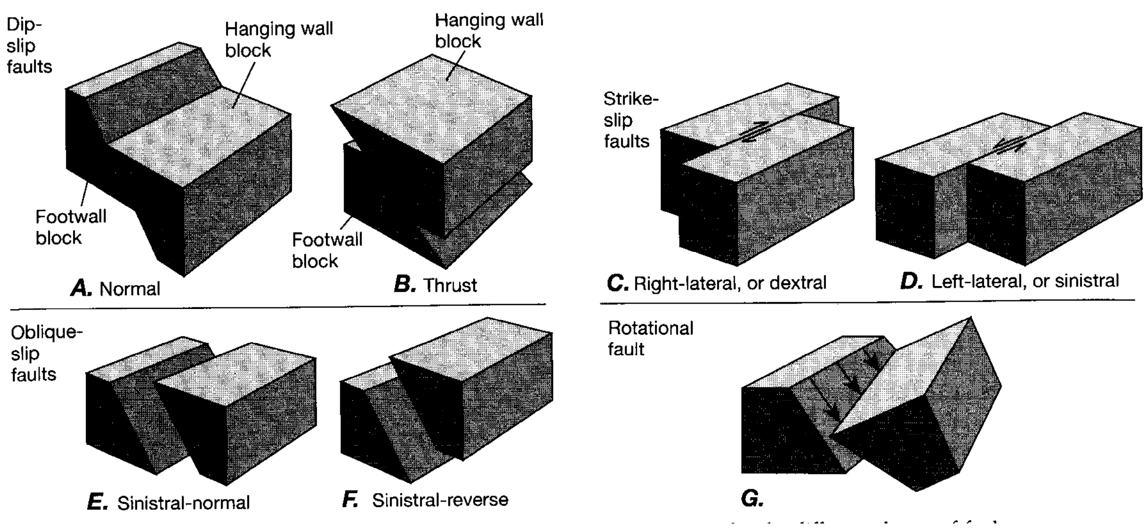

Fig. 3.18 *Relative displacement between faulted blocks for different classes of faults. (Twiss & Moores 1992)* .

3.1.3.3 Normal faults

In a normal fault, the block above the fault moves down relative to the block below the fault (Fig. 3.19, Fig. 3.20 and Fig. 3.21). This fault motion is caused by tensional forces and results in extension. Other names are normal-slip fault, tensional fault or gravity fault. Normal faults are an indication of a lengthening or extension of the Earth's crust. In areas with flat-lying beds found mainly in sedimentary basins, regional extension may lead to normal faults and associated rollover folds in the hanging wall block. This causes beds in the hanging wall block to tilt down towards the fault, which is opposite to the direction of tilt on drag folds.

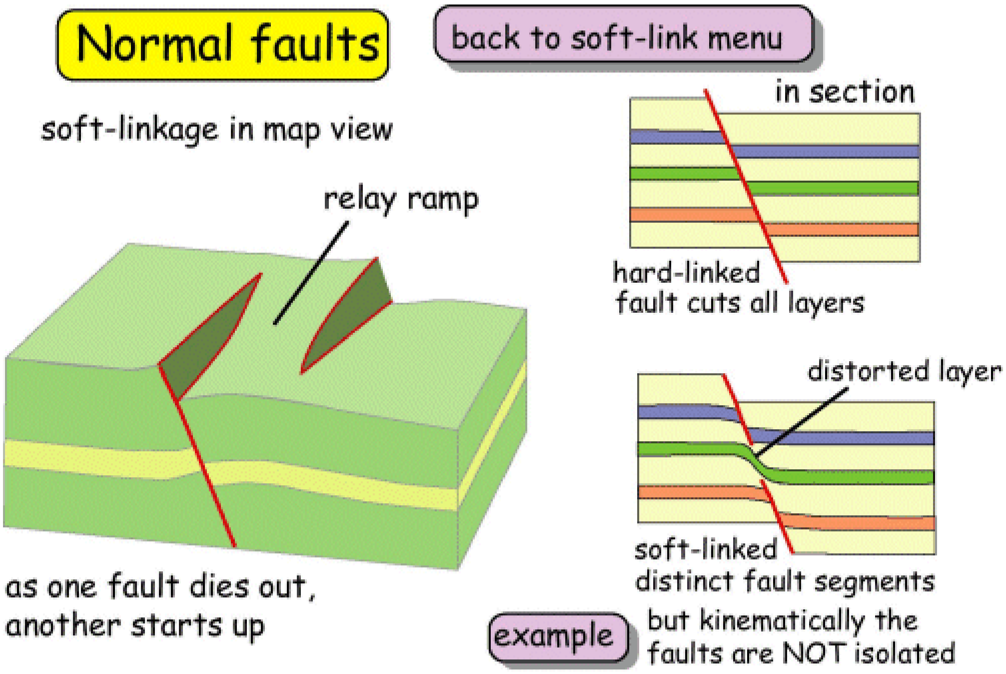

Fig. 3.19 *Geometry of normal faults. From http://www.see.leeds.ac.uk/structure/faults/soft/softnormal.htm*

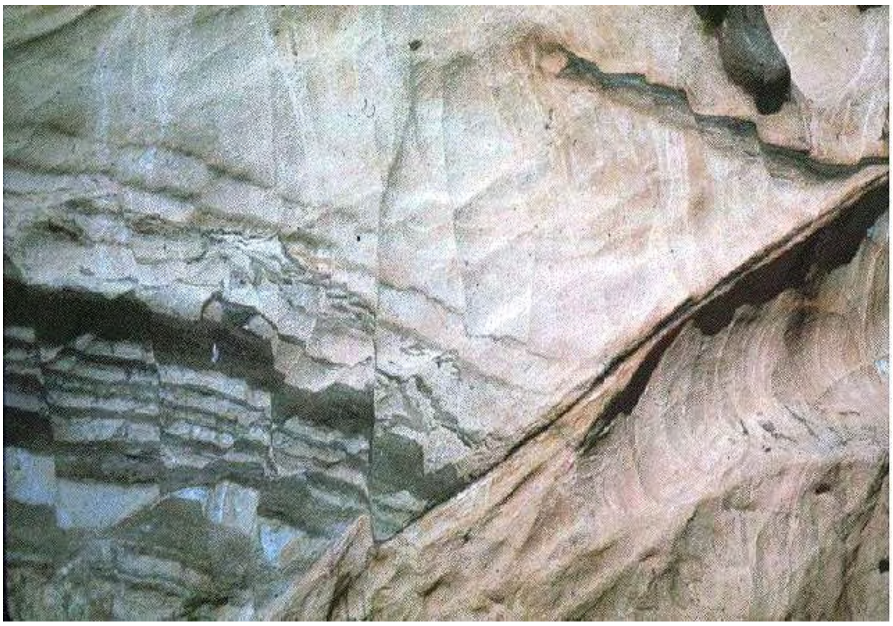

Fig. 3.20 *Example of smallscale normal faults. From* *http://www.geo.cornell.edu/geology/classes/RWA/GS_326/photo_galleries/normal_faults/hanging_wall_normal_faults.html.*

Fig. 3.21 *Normal fault in shallow marine sandstone of the Matulla Formation, Sinai. Throw is estimated to ca. 10 m. Note ramp-flat-ramp geometry, which is controlled by lower angle linkage of two fault segments in a thin shale layer. Photo: Alvar Braathen.*

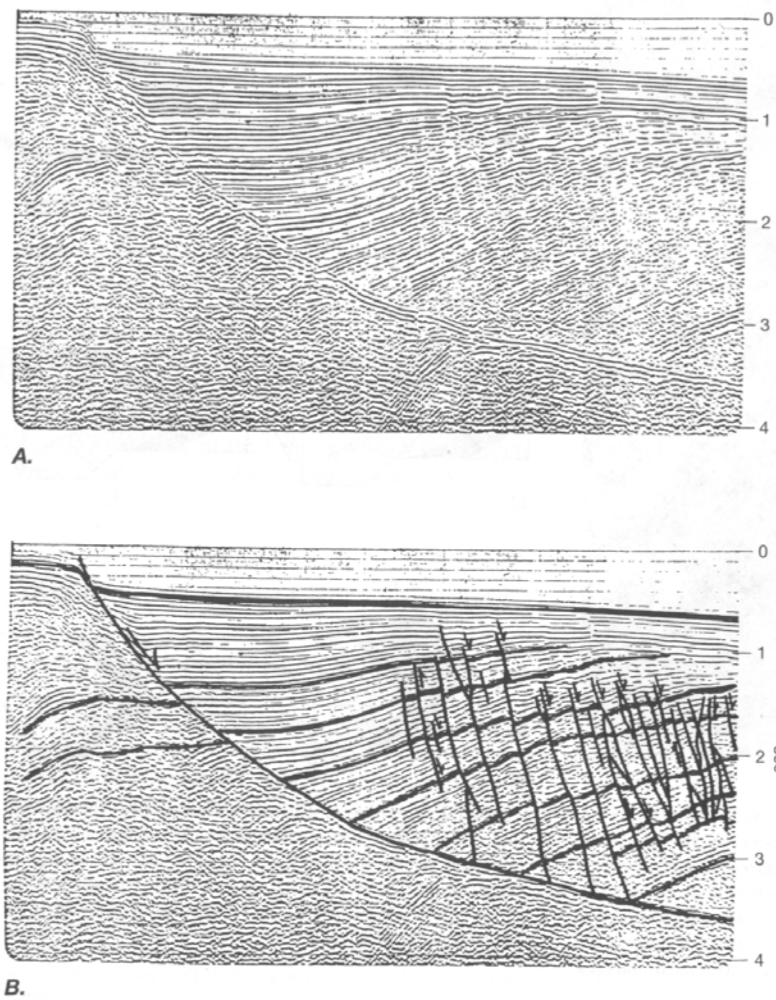

Fig. 3.22 *Seismic reflection profile of a listric normal fault (Twiss and Moores 1992) .*

Listric normal faults (Fig. 3.22) are concave-upward faults in which the dip decreases with increasing depth. At depth it is called a detachment fault, which is a low-angle fault that marks a major boundary between unfaulted rocks below and a hanging wall block above that is commonly deformed and faulted. Normal faults in the hanging wall block may form a set of imbricate faults, which are closely spaced parallel faults of the same type that either terminate against or merge with the detachment fault (Fig. 3.23).

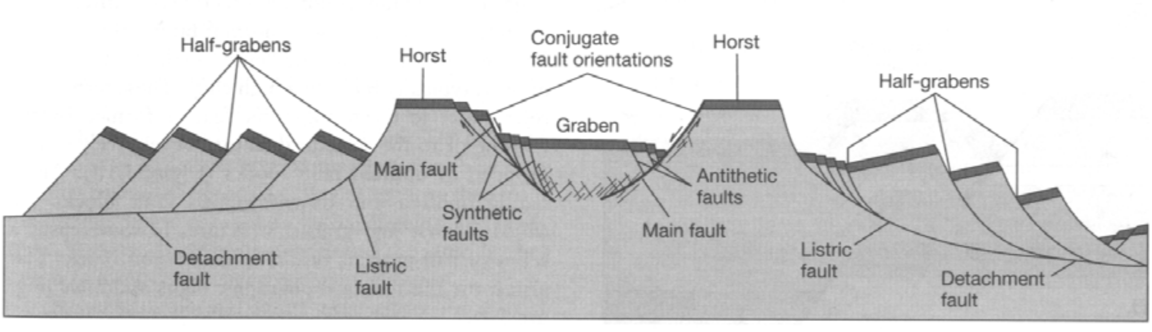

Fig. 3.23 *Sketch of a normal fault system in extensional area (Twiss and Moores 1992).*

There are many regional systems of normal faults forming distinct provinces around the world. The Basin and Range province in western USA is well known. It is assumed that all of the proposed SWP (South West Regional Partnership) and WESTCARB (West Coast Regional Partnership) sites are located in this province.

3.1.3.4 Reverse faults

In a reverse fault, the block above the fault moves up relative to the block below the fault (Fig. 3.24). This fault motion is caused by compressional forces and results in shortening. A reverse fault is called a thrust fault if the dip of the fault plane is small. Other names are reverse-slip fault or compressional fault.

Fig. 3.24 *Example of a reverse fault. From www.indiana.edu/~g103/G103/week9/wk9.html.*

3.1.3.5 Strike-slip faults

In a strike-slip fault, the movement of blocks along a fault is horizontal (Fig. 3.25). The fault motion of a strike-slip fault is caused by shearing forces. Other names are transcurrent fault, lateral fault, tear fault or wrench fault.

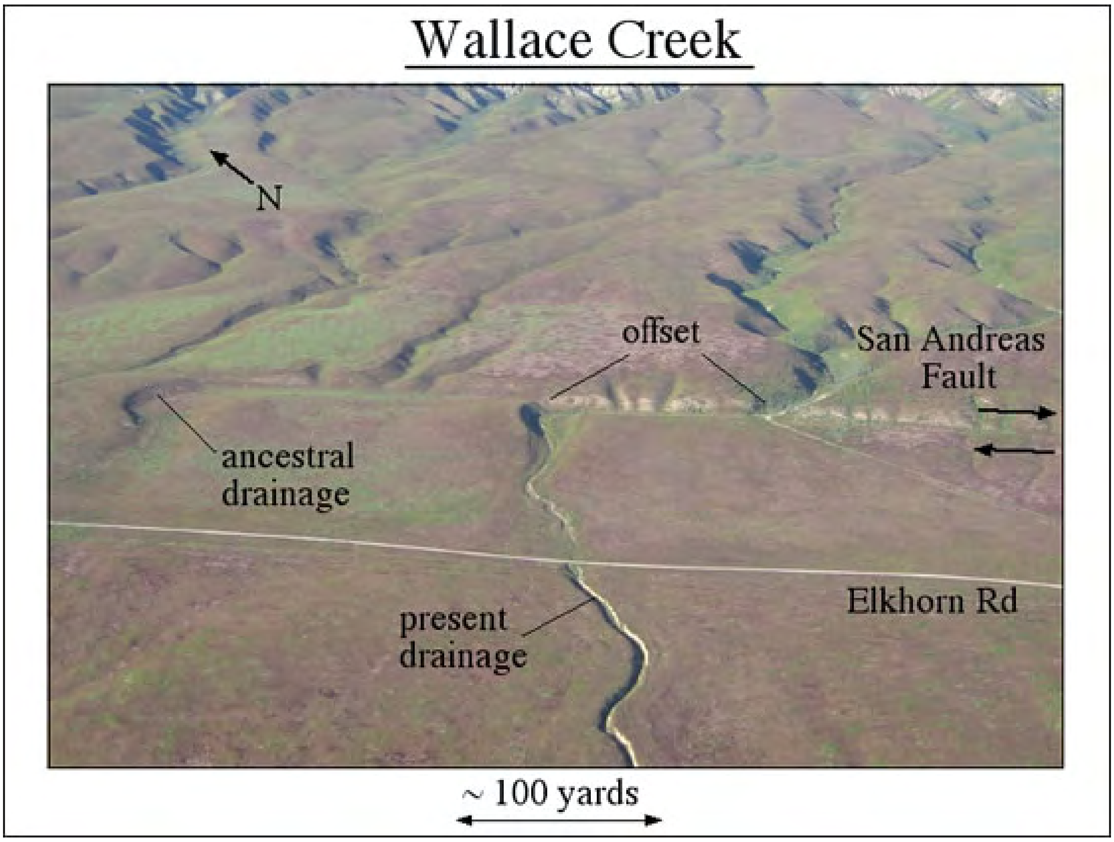

Fig. 3.25 *Example of a strik-slip fault: the San Andreas Fault in California. From http://geology.about.com/articles/images/san-andreas-fault-line.jpg*

3.1.3.6 Fault rocks

The type of fault rock is of great importance for determining whether CO_2 can leak through or along a fault or a fault zone. A detailed description of fault rocks was published by Davis & Reynolds (1996) and Braathen et al. (2004).

Brittle			← Deformation style →					Ductile		
Frictional flow			← Dominant deformation mechanism →					Plastic flow		
Non-cohesive			Secondary cohesion		Primary cohesion					% matrix and grain-size
			Cemented HB	Indurated HB			> 50% phyllosilicate	< 50% phyllosilicate		
Hydraulic breccia (HB)	Breccia series	Proto-breccia	Cemented proto-breccia	Indurated proto-breccia	Cataclasite series	Proto-cataclasite	Proto-phyllonite	Proto-mylonite	Blastomylonite	0-50% matrix
		Breccia	Cemented breccia	Indurated breccia		Cataclasite	Phyllonite	Mylonite		50-90% matrix
		Ultra-breccia	Cemented ultra-breccia	Indurated ultra-breccia		Ultra-cataclasite	Ultra-phyllonite	Ultra-mylonite		90-100% matrix
	Gouge		Cemented gouge	Indurated gouge						Sub-microscopic matrix
			Pseudotachylyte							

Fig. 3.26 *Classification based on deformation based on deformation style and mechanism, and cohesion during formation. Subdivisions are based on clast matrix distribution, for some rocks also including grain-size of matrix (gouge, pseudotachylyte), and phyllosilicate content (phyllonite versus mylonite). The diagram is modified after several authors specified in Braathen et al. 2004. Definitions are found in Table 1 of Braathen et al. 2004.*

Fault rocks can be classified in the following main types:

Mylonite is a foliated rock where the original grain size in the host rock is reduced by plastic and semiplastic deformation. Different types of mylonites ar classified according to degree of deformation and grain size. Mylonites can generally be regarded as sealing.

Cataclasite is a rock formed by mechanical crushing, i.e. by brittle deformation and formation of angular fragments (clasts) in a more fine grained ground mass (matrix). The fragments have no preferred orientation, and the fault rock is cohesive. A cataclasite has clasts of 0.1-10 mm, while an ultracataclasite has clasts <0.1 mm. Cataclasites are generally not sealing.

Breccia is a non-cohesive rock with angular fragments in a fine-grained matrix, created by mechanical crushing (Fig. 3.27). The fragments have normally no preferred orientation. Breccias may be cemented due to secondary precipitation of quartz and/or carbonate minerals. Breccias are generally not sealing.

Fig. 3.27 *Example of chert breccia. From http://geology.about.com/library/bl/wallpaper/n_wp_rocks_chertbrec2.htm*

Fault gouge is very fine-grained rock powder with a consistency like clay, created by extreme brittle crushing of the host rock. The grain size is <0.1 mm, but larger grains may occur. Due to low pressure and temperature hydrothermal alteration, rock powder in fault gouge is commonly altered to clay minerals, zeoliths and other minerals. Fault gouge is frequently considered to be sealing, especially if the rock powder has been altered to clay and other minerals, but this is not always so (e.g. Shipton et al. 2004).

3.1.4 Properties of fractures

3.1.4.1 Fracture morphology and permeability

Aspects of fracture morphology and permeability relevant to fluid flow have been summarized according to Nelson (2001, p. 61). The morphology of a fracture can influence the directional permeability of the surrounding rock mass. As a general rule, an open fracture will increase reservoir permeability significantly parallel to the fracture plane. This is not favourable for CO_2 storage at first glance, but geochemical reactions between CO_2 and reservoir rock may cause sealing. However, if so, it may affect storage capacity. In the case that the fracture is the width of only a few matrix pores (micrometers), reservoir permeability across the open fracture will be about the same as the matrix permeability in that direction.

Slickensides create great permeability anisotropy, because they increase permeability parallel to the fracture and decrease it across the fracture. The deformation along the walls of the fracture decreases reservoir permeability, as in gouge, across the fracture. However, due to the mismatch of smooth sliding surfaces, continuous interconnected pore space occurs along the fracture, which increases reservoir permeability parallel to the fracture. Vuggy fractures without diagenetic alteration of the vug walls should, as in open fractures, increase reservoir permeability parallel to the fracture and have little permeability effect across the fracture. Mixtures of the various morphologies can give unusual directional permeability effects and must be treated individually, often with 3-D whole core data.

3.1.4.2 Fracture and matrix porosity

In reservoirs or aquifers, where fractures are expected to play a significant role in storage of CO_2, the communication between fractures and matrix can best be assessed if they are treated as two different porosity systems, one system in the matrix and one in the fractures. In reservoirs or aquifers where the communication or interaction between these two systems is good, both porosity systems can respond to the overall fluid pressure gradient as well as directly to each other. However, if there is poor fracture/matrix interaction, this may or may not have been a problem during production, depending on the petrophysical properties of the two systems. An example here is the poor communication between a moderately porous, permeable fracture system and a low-porosity, high-water saturation matrix, which should not be a problem, versus a highly permeable fracture system and a matrix system with a large volume of potentially flowable hydrocarbons which represents a significant production and evaluation challenge. If the presence of an impervious lining to the fractures is not recognized, it will result in an erroneous estimate of the matrix contribution into the fracture system and then to the wellbore.

The properties of a two-porosity system and some misconceptions and nonparallelisms are:

1) Scale versus non-scale dependency
2) Porosity-Permeability relationships
3) Compressibility differences
4) Magnitude differences
5) Use of fracture volume instead of fracture porosity in evaluation
6) Significance of fracture porosity
7) Fracture porosity estimations
8) Core analysis
9) Fracture porosity –fracture permeability relationship
10) Field-Lab determination
11) Logs and log suites (NB! There is no direct method of calculating fracture porosity from well logs!)
12) Multiple well tests
13) Cross-flow in a two-porosity system
14) Examples of cross-flow in thin-section
    a. Uninhibited cross-flow
    b. Inhibited cross-flow
    c. Fracture mineralization
    d. Fracture deformation
    e. Estimation of porosity interaction)

(Saripalli et al. (2003), simplified fault flow calculation)

3.1.4.3 Geochemical reactions in fractures

If fractures cut the reservoir-caprock contact, geochemical interactions have to be assessed. Geochemical reactivity will only be significant if CO_2 (either free phase or dissolved in formation brine) is able to flow through the fracture. If the fractures were initially sealed, which is perhaps most likely, flow would probably require a pressure-induced event to create a leakage path. When assessing potential reactions in fractures it is of crucial importance to have information on the nature of any fracture-filling material and its mineralogy. Certain minerals might remain relatively unchanged when in contact with large amounts of CO_2, e.g. evaporites, while other mineral assemblages, e.g. carbonates, could react quickly. In the latter case, a widening of the fracture and an increase of the leakage rate may occur.

3.1.4.4 Sealing properties of faults

Cores sampled in the reservoir below may show oil staining, indicating that the reservoir has contained hydrocarbons earlier. This may indicate leakage paths that still exist, but more favourable storage conditions may have been formed since the leakage occurred.

It is difficult to assess the sealing properties of faults by direct sampling and testing methods. Sampling of faulted intervals is difficult, as fragmentation in the fault zone makes it difficult to obtain undisturbed cores suitable for laboratory measurements. In situ pressure tests with packers on each side of a discontinuity may give leakage results at a chosen spot, but the overall assessment will anyhow be uncertain.

Regarding the evaluation potential migration along faults, some observations in the subsurface (gas chimneys; small bright spots adjacent to faults, etc) may be indicators of potential leakage paths. In some land areas mud diapirs with high readings of hydrocarbon gases are observed. Similar observations have been done at the seabed, and both sea-floor mounds, sea-floor depressions (pockmarks) and associated carbonate cementation are indicative of fluid escape. In some cases pockmarks are concentrated along lineaments, which may be indication of leakage along faults or other discontinuities. If 3D data exist all such observations should be carefully addressed, in order to find out if faults through a reservoir have been the primarily source for leakage (Heggland 1998, Ligtenberg 2005). Comparison of the subsurface data and leakage-related features mapped from multibeam echo sounding must be carried out.

The stress state in and around faults may significantly influence whether a fault is conductive or not (Barton et al. 1995). Zoback & Townend (2001) suggested that many faults in the crust are critically stressed and are very near the point of failure as predicted from a Mohr-Coulomb failure analysis. The orientation of fractures in relation to the stress field is thus important.

The sealing capacity of faults depends of the type of structures that occur in the fault zone, how they are arranged, the contribution of each structure type to flow, and geochemical processes in the faults, which may add or remove sealing capacity (Shipton et al. 2004). Due to the poor preservation potential of faults in outrops of shale-rich rocks, few field analogues have been studied in detail, and there is little data to make predictions regarding the behaviour of these faults. They are often accounted for in hydrocarbon reservoirs using simple shale smear or gouge algorithms (e.g. Freeman et al. 1998). These make many assumptions about the fault, specifically that the seal is formed by physical smearing or mixing of the low-permeability clays in the host rock with no diagenesis of the fault rocks. Fault rock alteration and diagenesis would almost certainly take place within any CO_2 storage schemes that included faults (Shipton et al. 2004).

3.1.5 Fractured reservoirs

A “fractured reservoir” is defined as a reservoir in which naturally occurring fractures either have, or are predicted to have a significant effect on reservoir fluid flow either in the form of increased reservoir permeability or increased permeability anisotropy. A “reservoir fracture” is a naturally occurring macroscopic planar discontinuity in rock due to deformation or physical diageneses (Nelson 2001). If the fracture is due to brittle failure, it is initially open, but subsequently altered or mineralized. Fractures are characterized by their geometry, spacing, surface area and openings.

Before injection of CO_2 into a reservoir, it is advantageous to systematically assess the fractures in the reservoir as far as they relate to the mechanics of subsurface fluid flow by following a three-step evaluation sequence (Nelson 2001):

- Determine the origin of the fracture system.
- How do fracture properties affect reservoir capacity and performance?
- Assess communication between fracture and matrix porosity.

The process of understanding the fracture system at a particular storage site should thus start with classification of tectonic regime and geomechanical forces through time. This may help to determine the origin and age of specific fracture systems.

To assess the leakage potential of a “fractured reservoir” it is necessary to know the fracture permeability and the matrix permeability and how these interact. This requires combining fracture morphology and pore space distribution to estimate true reservoir permeability and permeability anisotropy below and adjacent to the caprock.

Fractures transecting a clastic reservoir, its caprock and overlying strata represent potential leakage paths to the surface. The main fault systems must be mapped, preferentially from 3D seismic. In the case of aquifer storage, excess pore pressure in the reservoir indicate that both caprock and faults are sealing. An automated 3D seismic interpretation as suggested by Ligtenberg (2005) should be carried out to map potential leaking faults. Based on 2D seismic data, it is difficult to assess if a fault represents a potential fluid conduit. Sealing capacity of faults cutting through the caprock of a reservoir can not be determined from seismic data.

If an exploited petroleum reservoir is planned for CO_2 storage, we know that the reservoir was sealed before production started. It is unlikely that petroleum production affects the sealing properties of intersecting or bounding faults. Theoretically, it is possible that the underlying source rock is still producing petroleum and that the reservoir currently both receives and looses resources by migration to other upstream reservoirs or to the surface. If such processes occur, they are probably much slower than the time spans we regard, i.e. thousands of years.

Pressure depletion of a petroleum reservoir causes its fractures to have a tendency to mechanically close. Information on when petroleum was extracted from a reservoir may help to determine when the fluid pressure declined as a function of time and caused changes in the value of some variables, but not in others. The initial calculations of transmissivity do not apply throughout the life of the reservoir. Therefore, some of the parameters have to be recalculated at several intervals during production from the reservoir. The production history of the reservoir with respect to variables affecting fluid flow, especially in the later stages, are valuable information in assessing the CO_2 storage potential and behaviour in the reservoir.

3.1.5.1 Faults in clastic reservoirs

Faults that are transecting a reservoir with clastic rocks, represent potential leakage paths to the surface, where the faults transect the adjacent caprock or roof rock and the overlying strata. The main fault systems must be mapped, preferentially from 3D seismic interpretation. Improved seismic interpretation methods, for automatic tracking of faults in the 3D volume, are currently under development.

Based on 2D seismic data it is commonly difficult to assess if a fault represents a potential fluid conduit. The improvements in 3D seismic acquisition-, processing and interpretation methods have recently contributed to improved methodology to detect fluid migration pathways (Ligtenberg 2005).

If an exploited petroleum reservoir is planned for CO_2 storage, we know that good sealing conditions existed before the production started. It is unlikely that the petroleum production has affected the sealing properties along intersecting or bounding faults. The fact that a petroleum reservoir exists in such a position is probably the best assurance we can obtain regarding good sealing conditions along faults. Theoretically it is possible that the underlying source rocks are still producing petroleum and that the reservoir currently both receives and looses resources by migration to other upstream reservoirs or to the surface. If such processes occur, they are probably much slower than the time-spans relevant for CO_2 storage, i.e. thousands of years.

Whenever storage in an aquifer is considered, seismic data generally cannot determine whether the faults penetrating and cutting through the roof rock are sealing. Measurements of excess pore pressure in a well through the reservoir may be indicative that both the roof rock and faults through the roof rock secure good sealing conditions. If 3D seismic data exist, a similar interpretation approach as suggested by Ligtenberg (2005) should be carried out.

3.2 Thief zones

'Thief zones'[6] are poorly defined smaller reservoirs that intersect and form a hydraulically continuous flow path between the primary storage reservoir and a formation at the same or much shallower depth at or near the storage site. In most cases such zones can only be mapped from good quality, high resolution 3D seismic data. Potential migration leakage paths from such zones towards the surface must be evaluated from all available data.

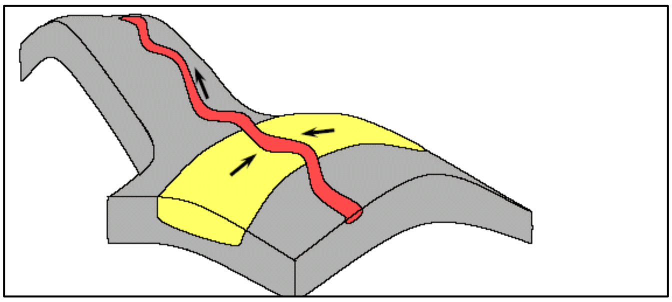

Fig. 3.28 *Cartoon of a thief sand. The younger, smaller red channel cuts into the larger, yellow channel, which is the primary target reservoir. CO2 migrates to the structural apex. In the absence of the red channel, the yellow sand body would charge with CO2, but with the thief sand, most of the CO2 is diverted to a different high, which may or may not close.*

In any given situation, where a petroleum field or groundwater aquifer is considered for CO_2 storage, the subsurface will be characterized by several compartments which might be feasible for storing smaller or larger quantities of CO_2. The relations between these might be complex and can be conceptualised as in Fig. 3.28. The best reservoir rocks will comprise extensive, well sorted sand- and gravel-grade sediments such as braided river-channel sheet sandstones, desert sands of eolian origin, spreads of littoral to sublittoral carbonate and clastic sands, delta front sands, shelf sands, reefs and reef talus, and proximal deposits of submarine fans (See Appendix). The distribution of these different sedimentary environments in the subsurface of a given oil field will be reflected in the special relations and status of the different reservoirs (Fig. 3.29). Each potential new infill reservoir considered as storage compartment needs to be assessed with respect to the presence of potential thief zones.

[6] A thief formation or zone is a formation that absorbs drilling fluid as it is circulated in the well. Lost circulation is caused by a thief formation. Also called a thief sand or a thief zone (US Dept. of the Interior, Offshore Minerals Management Glossary (http://www.mms.gov/glossary/ta-th.htm).

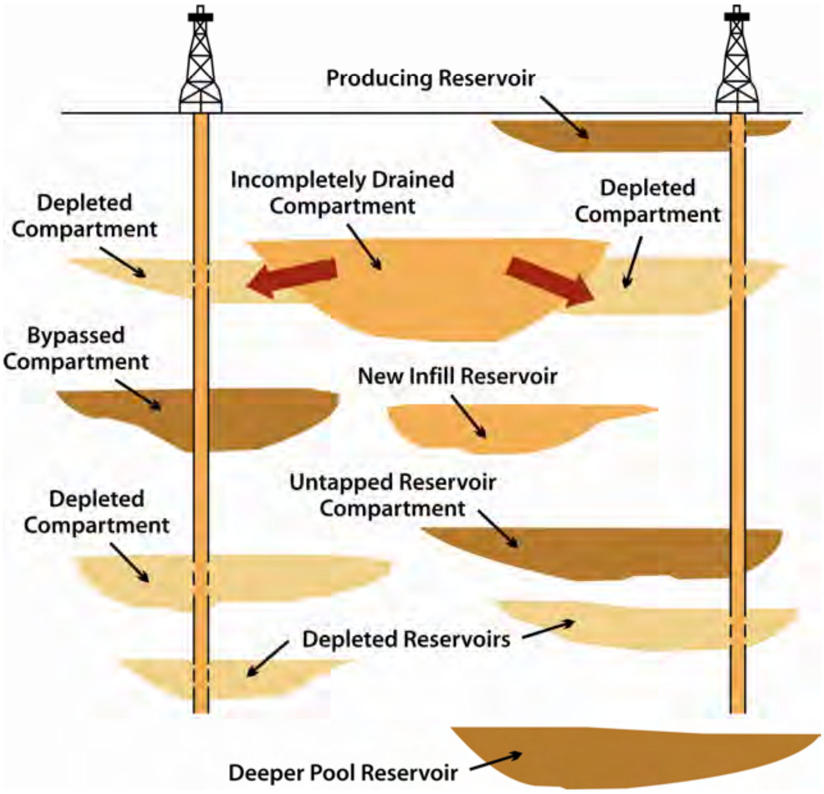

Fig. 3.29 *Vertical cross-section illustrating special relationship between different hydrocarbon reservoirs in mature oilfield approaching depletion and abandonment.*

At least one well with a suite of logs should document the lithology of the sedimentary succession above the caprock. Fine-grained layers often represent additional barriers preventing CO_2 to migrate towards the surface in case the trapping properties of the caprock fail. These strata often represent various rocks, and high permeability layers may represent leakage paths to the surface.

The challenge in delineating facies[7], which may act as leakage paths from the CO_2 storage reservoir or thief zones, consists of aquiring a three-dimensional distribution of sandstone channels and bars and carbonate reefs in the subsurface. This has usually been done by the lease-holder during exploration for hydrocarbons based on geological interpretations of geophysical data, primarily borehole SP and Resistivity logs.

Traps are usually sealed by compacted mudrocks or evaporites (e. g. halite), although leakage of oil and gas may occur during the early stages of formation of an oil and gas pool when compaction has not proceeded to its most efficient limit. Leakage from hydrocarbon traps are usually taking place at fault planes or zones, along which a secondary permeability is developed. As an example, in the North Sea, the fault zones are believed to be the migration path from the Jurassic to the Cenozoic reservoirs in the overburden.

In the Southern North Sea there has been production of hydrocarbons from reservoirs of Devonian age. These reservoir rocks are usually small alluvial fans derived from the footwall in hanging-wall regions, which yields immature, poorly sorted sediments, e.g. conglomerates. The alluvial fans tend to pass into distal sandy and muddy playa and terminal fan deposits over short distances, partially reddened due to oxidation by meteorically recharged ground water. Sometimes the playa alternated with shallow stratified lake deposits and sediments

[7] Facies are laterally equivalent bodies of sediment with distinctive characteristics

formed in reducing environments (Marshall and Hewitt 2003). The reservoir rocks are all low-permeability fluvial sandstones with production enhanced by a network of open fractures, and are not laterally extensive. Potential storage of CO_2 in these types of reservoirs would require a careful analysis of the leakage potential.

As an example, the Weyburn reservoir in Canada was investigated to determine how well it meets these criteria by mapping, stratigraphic distribution and extent of reservoirs, seals, regional aquifers, and aquitards from the Precambrian basement to the surface.

3.3 Wellbores

Introduction

a. Background

b. Previous and ongoing work

i. Field evidence (Texas, GoM), Texas, Canada, Australia)

ii. Experimental studies (Princeton, LANL, industry)

iii. Numerical models (Alberta, Princeton, LANL, IEA Borehole group)

II Processes related to Borehole leakage

a. Sustained casing pressure
b. CO_2 + formation fluid effects on cement
c. Metal corrosion of casing
d. Geomechanical effects on wellbores (localization of stress/strain, pressure cycling of wellbores, reservoir depletion and re-pressurization, reservoir competition, vertical casing and seats strain
e. Effects of age, type and age of completion, well type and (discussion from Bachu)
f. Design of sealing and plugging system in abandoned wells (requirements for milling before final sealing of wellbore, cement used in sealing, other fluids in abandoned wellbore, etc.)

III Probabilities

a. Field evidence (Bachu, Paine-Texas, IEA-GoM)
b. Lab experiments and contradiction in results (Princeton compared to LANL)
c. other risk assessments for sequestration – Australia and Weyburn

IV Data and Modeling Needs

a. Borehole, location, completion history/logs, annulus pressure if available
b. Models of fluid chemistry, size of plume and pH as it interacts with borehole materials
c. Models of size and location and aerial extent of possible plume

V Regulatory Impacts

a) For example, converging NM state regulatory guidance concentrates on boreholes during permitting stage. The regulations may also require modeling to determine size and nature of CO_2 plume

b) Updated compliance regulations for sealing CO_2 site wellbores to include new improved CO_2-resistent cements and other sealing innovations, "Updated Best Available Technology"

4. GEOCHEMICAL ASSESSMENT PRIOR TO INJECTION

While it is assumed that dry CO_2 in a dense phase is chemically inert, once it dissolves in water it will form carbonic acid. This will acidify the formation water and potentially attack and alter many types of rock. This can occur in the reservoir where CO_2 is injected, in the overlying caprock(s), in fractures present in the caprock and/or the reservoir and at the wellbores. These chemical interactions might change the physical characteristics of parts of the storage site and thus potentially enhance CO_2 migration towards the surface. The assessment of the geochemical impact is therefore an important aspect in assessing the safety of a CO_2 storage site, but also the long-term storage capacity. Much knowledge has been gathered as part of the SACS and CO2STORE projects and a major part of this chapter is taken from Chadwick et al. (2006, p. 135-153) with minor changes.

The volume of formation water and rock that can be displaced or compressed is usually unknown. Conceptually, closed (finite volume, closed boundaries) and open (laterally unconfined, infinite volume) structures can be distinguished. In the first case CO_2 can be stored by compression of the rock matrix and the formation water and by dissolution within the water only, while in the second case formation water can be displaced by CO_2. In practice CO_2 injection is a dynamic process however, with a transient pressure build up around the injection wells. After injection, a period of further expansion of the CO_2 phase, pressure relaxation, and dissolution in formation water follows. In large open aquifers pressure relaxation is fast due to the rapid displacement of formation water, as is the case of the Utsira Sand reservoir at Sleipner, where no significant pressure build-up has been observed. In closed aquifers pressure relaxation as a result of dissolution is slow. Thus, the volumes that can be displaced and compressed during the injection time determine the storage capacity within an aquifer structure. In order to establish the effective extent of a structure, knowledge of the hydraulic conductivity of faults in the vicinity of an injection site is required. This information can be derived from well tests. Variations of the effective aquifer radius in reservoir simulations can be used to study its impact on storage capacity.

In order to assess possible geochemical impacts at a storage site in the most reliable way, four steps have to be undertaken:

Baseline geochemical conditions at the storage site must be characterized properly **before the injection starts (Step 1),** leading to **the assessment of the initial geochemical status (Step 2)**. This requires a phase of data acquisition that differs from the usual practice in hydrocarbon operations, and consists of:

i. Geochemical characterization of the caprock, reservoir and fracture fillings (if appropriate).
ii. Characterization of the formation waters and measurement of the pressure and temperature conditions.
iii. Establishing the gas composition and chemical properties of the CO_2 to be injected. In the third step, a geochemical model of the water and rock system must be constructed, both for the CO_2 injection reservoir and the caprock, aiding **the assessment of the short-term geochemical reactions (Step 3)**. It is based on the initial characterization of the rock and formation water, and should be constrained

by laboratory experiments. These experiments will determine how the water and rock will respond to CO_2 injection, and provide input to better constrain the geochemical model, by determining some of the unknown geochemical parameters of the model (types of reactions, reaction rates and reactive surfaces). Results from these experiments are used to inform and calibrate the predictive geochemical modeling (at least over shorter timescales).

iv. **Long term predictive modeling (Step 4)** of the geochemical interactions has to be carried out. This is the only way to assess the geochemical impact of the injected CO_2 over hundreds to thousands of years. It can predict the effects of CO_2 formation pore waters, and the consequent changes in fluid chemistry and host rock mineralogy over the long term.

However, output from simulations is critically dependent on which reactions are taken into account and their underpinning chemical data (i.e. the simulations cannot predict phases or reactions which are not included within the database of the model). The outputs are also dependant on the reliability of the conceptual model chosen which requires a good expertise in aqueous geochemistry related to the interaction between sediments and natural waters at low temperatures.

The amount of uncertainty that can be reduced by performing a detailed sensitivity analysis on critical parameters has to be weighed against the computer processing demands which might limit the amount of simulations, i.e. iterations that can be performed. Further reductions in uncertainty can be made through comparison with observations from laboratory experiments (however, only in the short term), field monitoring at other CO_2 injection sites and knowledge derived from geochemical reactions observed at natural CO_2 analogue sites (Pearce et al. 2004). The latter can be particularly useful, but care should be taken not to misunderstand or over-interpret the observations from these very complex natural systems.

While the first step (baseline characterization) is described for both the caprock and the reservoir, the next steps are discussed separately in the sections focusing on reservoir and caprock reactivity. A brief section is added with respect to interactions in faults since in it is extremely difficult to collate data regarding their geochemical characteristics and to design specific experiments while modeling has to be performed on a very generic level.

4.1 Baseline geochemistry

Understanding the aqueous and sedimentary geochemistry of the system will require that the 'baseline' conditions of mineralogy and fluid chemistry prior to CO_2 injection is known. A program of sample acquisition needs to be developed, and this should be implemented prior to CO_2 injection. The baseline geochemistry can best be determined by analysis of suitably preserved borehole core material and pore waters. Focus should be directed at producing data on the mineralogical and chemical composition of reservoir and caprock formations prior to any CO_2 injection.

The mineralogical and chemical compostion of the reservoir and its properties needs to be known to quantify possible chemical reactions, and their reaction rates. Based on this, one may estimate the storage capacity and potential changes in porosity and permeability. Knowledge of the sealing capacity of the caprock is most important when assessing and establishing the long-term safety scenario for CO_2 containment in the given storage reservoir. Two aspects are important here; the natural seal (i.e. caprock), and the man-made seal around breaches in the caprock (i.e. boreholes). Caprock core material should be available in sufficient quantities to undertake a detailed suite of analytical tests. Physical, mineralogical and chemical properties of candidate theif zones needs to be tested. Ideally, samples of borehole cement should also be available for testing and analysis.

Also for the reservoir seal, knowledge on the mineralogical and chemical composition and its transport properties are required to quantify possible chemical reactions and their rates leading in this case to an estimation of the overall sealing efficiency. To determine these properties, a minimum prerequisite is to have core material from the caprock above where the CO_2 is to be stored. Core and cuttings material from additional wells will further improve characterization, particularly if vertical and lateral caprock heterogeneity is suspected.

It is recommended that the following data be collected:

1) Caprock and reservoir mineralogical composition. Analysis should include mineralogical and chemical characterization of solid phases, identification of detrital and authigenic phases and their specific surface areas (Table 4.1). Special attention should be paid to the identification of the exact composition of the clay and feldspars present, since these minerals are likely to contribute to the mineral trapping of CO_2 in the long term. Recommended analytical tools include optical microscopy, SEM (scanning electron microscopy), XRD (X-ray diffraction), electron microprobe analysis, particle-size analysis and BET (specific surface measurements).

Table 4.1 *Recommended analytical tools used for geochemical process analysis of solids.*

Method	Result	Application
Optical microscopy	Grain shape /Texture	Porosity/permeability variation
X-ray diffraction (XRD)	Primary minerals	Sediment-type/Storage capacity
Scanning Electron microscopy (SEM)	Secondary minerals	Burial history/Storage capacity
Electron microprobe analysis (EMA)	Authigenic minerals	Burial history/Storage capacity
Particle size analysis (Coulter®)	Grain size	Determine Depositional environment/Uniformity
Surface area analysis (BET)	Area reactive minerals	Estimate reactivity relative to CO_2 exposure

2) Reservoir pore water composition (Table 4.2). Water can be collected either down-hole or at the surface. For all surface sampling, water flow rate and gas-water ratio as well as non-conservative parameters (e.g. temperature, conductivity, pH, Eh, alkalinity) must be measured on site (Hem 1970, Lindberg and Runnells 1984, Hitchon 1996, Morel and Hering 1993, Drever 1997a). This is because samples taken at the surface are prone to chemical modifications, mainly degassing, but also possibly cooling and mineral precipitation. Formation water, which is pumped up as part of production may lead to mixing of water from various reservoir units, and indirect calculations are needed to assess the reservoir formation's pore fluid chemistry at depth. Suitably preserved samples of gas and water can subsequently be analyzed for their compositions in the laboratory.

Down-hole water sampling enables the retrieval of pressurized samples, but care has to be taken to avoid pollution of the water sample from drilling fluids. Although in ideal circumstances such down-hole samples would be preferable, their recovery requires specific tools and know-how, is costly, and is generally not common practice. These two techniques assume that water is mobile in the injection site, which may not be the case, especially when water is injected in a depleted hydrocarbon reservoir. In such cases, alternative techniques have to be tried, possibly involving similar approaches to those used to evaluate the composition of caprock pore-water.

3) Caprock pore water composition. It is much more difficult to get a water sample from a caprock, as the water mobility and content is extremely low. The following two core-based techniques are available. First, caprock pore waters can be extracted from core material. However, the water sample obtained is not representative of *in situ* conditions at depth and additional information on gas-water ratios and gas content has to be obtained, ideally from the same well. Moreover pore waters extracted from core material are often contaminated by drilling fluids and corrections have to be made to assess the actual fluid chemistry. Second, caprock pore-water chemistry can be reconstructed from residual salt analysis whereby formation water salts are collected from a water percolation test in a core plug.

Several residual salt analysis methods can be mentioned:

i. Elemental residual salt analysis, to establish the water chemistry from shaly samples.
ii. Water salinity from plugs cut in hydrocarbon bearing intervals.
iii. Sr-residual salt analysis, based on the analysis of the isotopic composition of strontium ($^{87}Sr/^{86}Sr$), which is an indirect method that must be implemented with care.

In summary, laboratory data to be acquired to assess the water chemistry include the following minimum range of parameters: 1) Cations (e.g. Li, Na, K, Mg, Ca, Sr, Ba, total Mn, total Fe, Al, Si, total S, and others as necessary), 2) Anions (e.g. HCO_3^-, Br^-, Cl^-, SO_4^{2-}, and others (e.g. HSO_3^-) as necessary), 3) pH with corresponding temperature, 4) Alkalinity, 5) Total inorganic carbon (TIC), and 6) Total organic carbon (TOC).

Table 4.2 *Field and laboratory data to be acquired to assess the water chemistry.*

Method	*Result*	*Application*
Inductively coupled plasma spectrometer (ICP-AES)	Concentration of ≈30 elements	Porewater/rock-mineral reactions
Ion chromatography (IC)	Anions (Br-, Cl-, F-, SO42- etc.)	Porewater/rock-mineral reactions
Titration	Alkalinity	Porewater/rock-mineral reactions
Self Potential Electrode	pH, redox-couple(s)	
Combustion w/IR-detection	Total carbon (TC)	Total inorganic carbon (TIC)
Combustion w/IR-detection	Total organic carbon (TOC)	Subtract from TC to get TIC
Geochemical modeling	Activity of ions, speciation	Reactive minerals
Flow modeling	Flow rate and uniformity	Recharge/Discharge areas
Coupled modeling	Mineral dissolution/cementation	Long-term CO_2 storage capacity and migration

Pressure and temperature conditions in the reservoir and caprock

Pressure and temperature conditions have an important impact on the type of geochemical reactions that will occur, as well as on their reaction rates, and should be measured with great care. Also the presence of temperature and/or pressure gradients should be established. Physical parameters of the reservoir and caprock that are needed to perform coupled flow and transport models are porosity, absolute and relative permeabilities and capillary entry pressure as well as diffusion rates in the case of caprock characterization.

4.2 Reservoir geochemistry

The reactivity of dissolved CO_2 in the reservoir will act as an open system from a geochemical point of view, meaning that dissolved CO_2 is likely to be in excess and will not limit the reactivity. Dissolution of CO_2 will decrease the pH of the pore-water significantly, and most likely lead to rapid dissolution of carbonates. The result of this may be local increase in porosity, especially around the injection well. In the longer term, slower reacting minerals, e.g. aluminosilicates, will dominate the geochemical interactions depending on the mineralogy of the host rock. When sparse and slow reacting aluminosilicates are being dissolved and only a minor amount of cations is liberated due to CO_2 interactions, small amounts of the dissolved CO_2 will become trapped as carbonates, i.e. by mineral trapping. In such cases carbonate dissolution might be dominant even over long timescales. However, when the mineralogy of the host rock is such that substantial amounts of host rock aluminosilicates can be altered, substantial carbonate precipitation may occur, during which large amounts of dissolved CO_2 might be trapped. In such cases mineral trapping can become significant and might locally decrease the porosity of the reservoir in the long term.

The interaction between flow and geochemical reactions requires that a coupled modeling is performed in which one takes into account the geometry of the reservoir, the flow of the phases involved, e.g. dense phase CO_2, brine, oil, gas through the reservoir as well as the geochemical reactions between flowing formation pore waters and minerals constituting the reservoir lithology (Table 4.3). These types of models are also crucial for calculating the time evolution of CO_2 dissolved in the pore-water over time, since in most reservoirs solubility trapping is expected to dominate over mineral trapping (Steefel et al. 2005).

If a full and detailed analysis of the reservoir formation water is not available, then it may be possible to use geochemical modeling to estimate the missing data based on formation mineralogy. This requires mineralogical analysis of reservoir rock samples. Minerals present in the host rock can be selected to fix the missing concentration data (e.g. by equilibrating with chalcedony or quartz in case Si concentrations were not measured, and with kaolinite in case Al concentrations were not measured) or where pH measurements seem unreliable. Furthermore an initial analysis should be made with respect to the minerals that should be included in the geochemical models taking into account temperature and pressure conditions as well as detailed mineralogical analysis and SEM imaging if possible (Table 4.1). Thermodynamic and kinetic data with respect to these minerals should be selected with care (Robie et al. 1979, Aagaard and Helgeson 1982, Nordstrom and Munoz 1994, Marini 2007). In this step, pre-dimensioning modeling can also be performed to get preliminary insights into the potential reactivity of the caprock when in contact with pore-water modified by the dissolution of CO_2.

4.2.1 Sample acquisition and chemical analysis

Mineral trapping of CO_2 via precipitation of carbonates depends on availability of aqueous metal cations, originating from non-carbonate minerals, primarily metal bearing silicates. Carroll and Knauss (2005) found that dissolution rates of these are negligibly affected by the presence of aqueous CO_2, and can be accurately predicted as a function of Oelkers et al. (1994) feldspar dissolution model. Golubev et al. (2005) studied the dissolution rates of diopside, forsterite, wollastonite, and hornblende, and did not find any direct effect of CO_2, and concluded that the pH of the aqueous solutions in direct contact with these mineral surfaces is the major factor influencing dissolution rates. Geochemical modeling of how CO_2-rich water influence silicate and carbonate mineral dissolution rates, can be accurately determined by simply taking into account the presence of CO_2 on solution pH. Kaszuba et al. (2005) attempted to replicate what happens when a CO_2-rich NaCl-bine at 200 ºC react with a mixture of quartz, feldspar, biotite, and shale. Most importantly magnesite and siderite were formed validating the potential for mineral trapping. Xu et al. (2005) considered what happens when CO_2 is injected into a common sedimentary sequence considered for CO_2 storage; a sandstone bounded by a shale. They found that the total quantity of CO_2 trapped in carbonate minerals will depend on the rock composition, but up to 90 kg/m^3 of CO_2 can be trapped for up to 100,000 years, mainly in the sandstone, depending on the supply of aqueous metal cations in the adjacent shale. However, the interaction of the acidic CO_2-rich fluids with shale can go two different ways. Either the metal cations provided will enhance the carbonate precipitation and thus the trapping of CO_2. Or, the leaching of these metals from the shale may increase its permeability and open up potential migration paths to the atmosphere as suggested by Moore et al. (2005). The caprock should not experience serious dissolution caused by carbonic acid during the long-term storage. Ideally the reservoir rocks should be inert to reactions with injected CO_2. In a pure quartz sandstone reservoir this is close to being the case (Blatt et al. 1980, Bjørlykke and Egeberg 1993, Renard et al. 1997).

The presence of other substances together with CO_2 when it is injected (e.g. H_2S) may have an important impact on the geochemical interactions in the reservoir as well as on its phase behavior. It is therefore necessary to establish the exact composition of the CO_2-stream, and its anticipated temperature, during injection in order to acquire the data necessary to establish its phase behavior. The impact of certain impurities can be assessed using existing geochemical models, but the results depends on the type of impurities. Unfortunately, it was not possible to determine a realistic composition of the pore water present in the caprock at Sleipner, because of significant contamination by drilling fluid. But the CO_2 injected into the Utsira Formation at 700-900 m b. s. fl. (about 1000m b. s. l.) contains <2% CH_4 and some heavier hydrocarbons.

Table 4.3 *Possible mineral assemblages relevant for reservoir (clastic or carbonate) dissolution/precipitation simulation.*

Mineral(s)	*Mineral(s)*
qtz(s) → qtz (aq)	forsterite
kaolinite ($Al_2Si_2O_5(OH)_4$)	magnesite
K-feldspar → kaolinite	talc
biotite ($KMg_3AlSi_3O_{10}(OH)$)→ kaolinite	serpentine
plagioclase ($Na_{0.62}Ca_{0.38}Al_{1.38}Si_{2.62}O_8$)	epsomite
plagioclase → kaolinite	dawsonite
smectite ($Ca_{0.17}Al_{2.33}Si_{3.67}O_{10}(OH)_2$) → illite	nahcolite
plagioclase → smectite	calcite
montmorillonite ($Ca_{0.33}(Mg,Fe)_{0.67}$	dolomite
illite	ankerite
Chlorite → Mg-chlorite	siderite
anorthite	brucite
albite	calcium hydroxide
hornblende	gypsum
epidote	anhydrite
diopside	pyrite

4.2.2 Short-term geochemical modeling

Shorter-term geochemical reactions (ranging in length from minutes to several months) are well suited to be studied in the laboratory. It is not difficult to design and build experimental systems that can mimic in situ conditions that might be found in the top few kilometers of the Earth's crust. The complexity of the experiments undertaken will depend upon the specifics of the study or the storage site in question, and which data are required. The minimum requirement however is to perform, simple 'batch' experiments. In these samples of the reservoir rock would react with a representative pore water composition with or without CO_2, under representative in-situ pressure and temperature. Conducting experiments in pairs (i.e. with and without CO_2) allows purely CO_2-induced reactions to be discriminated from possible experimentally-induced anomalies. Periodic sampling of the fluid phase(s) can be used to follow the progress of reaction in real time, whereas mineralogical analysis of the solid phases at the end of the experiments can provide detailed information on which minerals did dissolve or precipitate during the experiments. Although laboratory experiments will only tend to investigate time periods of months to a very few years, they are necessary, since they may provide the detailed and well-constrained data against which predictive computer models can be calibrated. The modeling of simple batch experiments using geochemical codes based equilibrium is relatively straightforward, and the dominating mineral dissolution and precipitation reactions can be followed by observing the degree of saturation with respect to individual minerals as a function of time.

The rates of reaction between aqueous fluids and rock can be relatively slow. Thus it may take several months (or over a year) for significant fluid-rock reactions to occur. Grinding of the rock sample increase the mineral surface area which comes in contact with the aqueous fluids. This will in general, speed up the reactions. However, care must be taken not to expose unrepresentative mineral surfaces. As an example, the reaction of an intact piece of sandstone where all the quartz grains are coated with a thin layer of iron oxides will be very different from the reactions of a disaggregated sample of the same material where the oxide coating has been removed by abrasion or dissolution. Although raising the temperature of the experiments can increase the rates of reactions, i.e. in an attempt to compress many years of reaction into a few weeks, applying unrealistically high temperatures can also favor unrepresentative reactions. These might result in the precipitation of ‘unexpected’ secondary minerals, e.g. the precipitation of calcium as an aluminosilicate phase at high temperatures rather than as calcite.

By using adequate geochemical computer codes one can fairly accurately model short-term reactions involving real rocks whether they are part of an experiment or are found deep underground. However, certain basic kinetic data as well as thermodynamic data are part of the databases accompanying the computer codes. Although various databases of thermodynamic data exist, databases with kinetic parameters are scarcer, and not necessarily available in the literature. Kinetic parameters are particularly important when considering conditions far from equilibrium, such as when a plume of CO_2-rich water passes through a rock for the first time. Conditions far from equilibrium are particularly relevant for short-term experiments on specific mono-mineralic aggregates. With appropriate kinetic data, it should be possible to model not just the end point of a particular laboratory experiment, but also how long it will take for the experiment to get there. Further research is needed in this area (Aagaard and Helgeson 1982, Nordstrom and Munoz 1994, Steefel et al. 2005).

Using simple ‘batch’ experiments one tone may identify the types, rates and magnitudes of reactions between CO_2/water/rock, However, they can not simulate the complex interplay between kinetically-controlled dissolution and precipitation reactions possibly taking place and the overall fluid migration through rocks. Simulating this complexity is necessary in order to make accurate predictions about the future evolution of real CO_2 storage schemes. For example, the precipitation of secondary minerals may be relatively slow compared to the dissolution of primary phases. As a consequence, CO_2-rich water flowing through a rock may produce a series of reaction fronts that migrate over time. These are likely to be associated with changes in porosity, and thus impact fluid flow. Although various reaction-transport codes, also referred to as coupled models-, have been developed, they tend to produce somewhat ‘idealized’ models (Knaus et al. 2005, Steefel et al 2005).

Laboratory experiments involving CO_2/water/rock reactions with flow of interstitial waters, can provide the well-constrained and detailed data that are needed to refine preliminary models. For example, a model may predict a series of narrow and discrete reaction fronts after a certain time period. However, experimental observations could reveal reaction fronts that are more gradual and diffuse. Complex flow experiments can also show that rates of mineral reaction (or reactive mineral surface areas) can be very much lower than literature values (e.g. Chernichowski-Lauriol et al. 1996, Drever, 1997a, Rochelle and Moore 2002, Rochelle et al. 2002, Rochelle et al. 2004, Gunter et al. 2004, Johnson et al. 2004, Bateman et al. 2005, Durst and Gaus 2005, Gaus et al. 2005, MacQuarrie and Mayer 2005, Steefel et al. 2005).

As an example, 1-D reaction transport modeling was carried out early in the CO2STORE project (Gaus et al. 2005). More sophisticated 2D and 3D reaction transport modeling was carried out as part of the operations phase. The studies within the SACS and CO2STORE projects (Chadwick et al. 2006) all concluded that dissolution and precipitation may occur as a result of the acidity of dissolved CO_2. However, the geochemical reactions are not expected to cause severe damage to the caprock lithologies within the reservoir.

4.3 Caprock geochemistry

The potential geochemical impact of CO_2 injection on the caprock needs to be assessed in advance, since it is not unlikely that the caprock might be affected in a significant way with respect to its ability to seal or cap the CO_2. At a properly selected storage site, one may assume that free CO_2 will be unable to effect capillary penetration into the caprock. Therefore CO_2 will only be able to enter the caprock by diffusion when being dissolved in the brine. Diffusion is a very slow process and even on long timescales only the lower section of the caprock is likely to be exposed to CO_2-saturated formation waters.

Chemical reactions in the caprock will be limited by the amount of CO_2 available, and are likely to behave as a closed system from a geochemical point of view. The availability of CO_2 is limited by the slow diffusion process. This will cause CO_2 to be consumed mainly due to geochemical interactions, which will further retard the movement of the diffusion front. Carbonate dissolution is likely to be limited to a very thin section at the base of the caprock, potentially inducing a slight increase in porosity. However, higher up in the caprock alumino-silicates are likely to dominate the geochemical interactions, leading only to minor changes in porosity depending on the specific caprock mineralogy. As an example, the shaly layers within the Utsira Sandstone have extremely low permeability. When the CO_2 liquid encounters these layer, the clay minerals expands and the shaly layers become even more compact.

As was the case for the reservoir, caprock data need to be integrated into a coherent dataset, especially with respect to the composition of the caprock formation water, since establishing pore water composition in low permeability caprocks is extremely difficult. The same procedure should be followed as described in the case of the reservoir rock (see section above).

4.3.1 Short-term geochemical modeling

The laboratory investigation of short-term CO_2-water-caprock reactions is, in many ways similar with the approach suggested for reservoir rocks. As for the reservoir rock experiments, care must be taken not to induce anomalous or unrepresentative reactions which are not realistic in nature. This is particularly important with samples of clay-rich caprocks, which may be more sensitive to changes e.g. in temperature. However, in experiments assessing fluid flow through rocks, a significant difference exist between how caprock and reservoir rocks behave. For reservoir rocks these types of experiments are relatively straightforward, and can produce useful data. However, they are more problematical for caprocks as they have (by definition!) very low permeabilities. Samples from relatively long duration experiments, e.g. twelve months, studying CO_2 flow or diffusion through a sample of caprock could be analyzed for mineralogical changes. However, the degree of reaction may be relatively minor and hard to investigate if only a little CO_2 has passed into the caprock sample. More appropriate to the study of short-term interactions would be the simulation of CO_2-saturated water moving along a fracture in a caprock.

Experience from long term diffusion modeling has been gained from three sites within the CO2STORE project (Chadwick et al. 2006). Diffusion was assumed to be the dominant transport process in the caprock, occurring mainly in a vertical upward direction, allowing the use of simpler conceptual models including only one dimension. In the reservoir, where density induced flow as anticipated, realistic coupled models require at least two dimensions. All results from the modeling were comparable, indicating that major caprock deterioration due to diffusion of CO_2 into the caprock is unlikely, under the condition that no free, i.e. supercritical CO_2 enters into the caprock.

In the CO2STORE project (Chadwick et al. 2006) it was also found that, depending on the reactivity of the caprock, vertical diffusion of CO_2 seems to be retarded by the chemical reactions. The calculated porosity changes were small and limited to the lower few metres of the caprock. A minor decrease in porosity is predicted, which would tend to slightly improve the sealing capability of the caprock. This is due to the predicted alteration of plagioclase into calcite and dawsonite, as well as chalcedony and kaolinite. Only when Ca-rich plagioclase is present will this reaction and subsequent porosity decrease be significant. However, at the base of the caprock some carbonate dissolution might occur.

4.3.2 Long-term geochemical modeling

The SACS and CO2STORE projects (Chadwick et al. 2006) have, in addition, assessed the chemical impacts of CO_2 injection on reservoir rocks in the Utsira Formation at Sleipner, and various other caprocks and reservoir rocks from a number of case-studies, via long-term geochemical modeling and laboratory experiments. The main results are summarized below:

-Two complementary reservoir modeling strategies were developed to focus either on the effect of the silicates or on the spatial localization of the reactivity.

-The reservoir in the Utsira Formation is most likely only slightly reactive due to its mineralogy and low temperature, i.e. very slow reaction rates.

-Any reactivity in the caprock induced by diffusing CO_2 is expected to be minor.

-Reactivity of mineral-filled faults depends on the nature of the mineral fill.

Fault and fracture geochemistry
Reactions favoring both increased and decreased fault permeability can occur. Severe reactivity of carbonate rich fault-wall rocks can lead to potential geomechanical instability of the fault-walls. Batch modeling was performed to assess the geochemical interactions in a closed system using the local equilibrium hypothesis. Since detail on the exact composition of the fracture filling is not available, a sensitivity analysis was carried out with respect to the composition of the evaporites, assuming different representative mineralogical make-ups (Chadwick et al. 2006, Figure 4.37). Assuming that the fault is filled with evaporitic minerals, preliminary modeling for different evaporite compositions indicates that the presence of CO_2-rich formation water will not lead to dissolution of the fracture filling. On the contrary, it is possible that minor precipitation would occur, leading to mineralogical volume increase and to possible sealing of leakage pathways. Only in the extreme case where dolomite makes up the bulk of the evaporite minerals would dissolution become important. However, such an evaporite composition is very unlikely.

5. FLOW SIMULATION

Flow modeling is a key element in the characterization phase of a CO_2 storage project, providing quantitative predictions of reservoir behavior and, via multiple realizations, parameter sensitivity to uncertainty. Generically it serves to demonstrate that we understand the basic reservoir system processes. More specifically, it can be used to refine capacity estimates, to evaluate the likely lateral spread of CO_2 in the future, which is essential for designing effective monitoring programs, and to examine putative leakage scenarios relevant for site risk assessment. Preliminary long-term modeling can also be carried out to support the overall site safety scenario.

The main data requirement for flow modeling is some form of 3D geological model, attributed with reservoir and overburden parameters including caprock characterization. Reservoir parameters should be based on core measurements if possible, supplemented by geophysical logs to gain more robust area coverage. Necessary parameters for modeling include:

A)Reservoir
1) Temperature
2) Pressure
3) Porosity
4) Permeability
5) Relative permeability curves
6) Capillary pressure curves

B) Caprock
1) Permeability
2) Capillary entry pressures
3) Fluids
4) CO_2 composition, presence of impurities and physical properties
5) Salinity
6) Phase behavior

6. VERIFICATION PROCEDURES

Operators applying "governmental" or "verification bodies" for approval of CO_2 storage in subsurface reservoirs are expected to document that they have acquired the necessary data for storage assessments. Based on geological models constructed from these data and the general geo-knowledge of the actual area, a set of simulation models of subsurface fluid-flow, pressure build-up etc., should document that safe long-term storage is feasible. The utilisation for a Storage Project should also describe operational and development plans regarding both CO_2-injection and monitoring of fluid flow within the reservoir (Table 6.1). The proponent should also evaluate the risk for potential hazards related to storage of CO_2.

Table 6.1 *A* CO_2 *storage project comprises three main phases*

1. Pre-injection phase	• Compilation of available geological information • Planning Injection Wells and Injection Procedures. • Acquiring new data • Planning Hydrocarbon Production and re-cycling of CO_2. • Planning Water Production Wells (to prevent hydraulic fracturing). • Modeling and Simulation based on the Geological Model and Operational Plans. • Planning monitoring the CO_2 fluid flow versus time
2. Injection phase	Covers the period during which injections in the reservoir occurs • Monitoring fluid flow • Re-evaluation of planned operations
3. Post-injection (Abandonment) phase	Covers the period after the Operator has completed the injections, after the responsibility has been transferred to the public sector. • Monitoring fluid flow

A successful CO_2 storage project depends on (Table 6.2):

1) Good reservoir. A reservoir located at a depth where the pressure and temperature conditions allow CO_2 to be in a liquid phase (c. 900 – 2500 m below sea surface or land surface). Furthermore, the reservoir has to fulfil several demands with respect to geological, mechanical and physical properties.

2) Good caprock. The caprock above the reservoir should have low vertical permeability and be thick enough to capture CO_2. Some additional requirements for caprock properties may be of importance, e.g. ductile strength and resistance towards chemical reactions. The succession of strata above and adjacent to the reservoir, and their geometries, may represent either additional CO_2 migration barriers or possible migration 'thief zones', and must be regarded in the overall assessment.

3) No discrete leakage paths. If faults intersect the reservoir rocks, they should not be open conduits to the surface or the seafloor. If faults terminate in the succession above the reservoir, good sealing properties of the uppermost sediment succession must be documented. The overburden and especially the caprock of previous hydrocarbon reservoirs should not be fractured as a result of compaction during exploitation. The faults should not be connective with permeable layers outcropping at the sediment surface or sub-cropping close to the surface. Abandoned wells should be plugged, e.g. sealed with concrete, according to accepted procedures.

Table 6.2 *Indicators for evaluation of feasibility of* **CO_2** *storage*

	Positive Indicators	*Cautionary Indicators*
Total Storage Capacity	Total capacity is estimated to be much larger than the total amount produced from the CO_2 sources	Total capacity is estimated to be about the same as the total amount produced from the CO_2 sources
Depth of reservoir	>1000 m <2500 m	< 800 m, > 2500 m
Reservoir thickness	> 50 m	< 20 m
Porosity	> 20%	< 10%
Reservoir brine salinity	> 100 g/l	< 30 g/l
Caprock lateral continuity	No faults	Lateral variations, faulted
Caprock thickness	> 100 m	< 20 m
Capillary entry pressure	Entry pressure is much greater than the sum of the buoyancy force of a CO_2 column and the increased reservoir pressure due to CO_2 injection	Entry pressure is similar to the sum of the buoyancy force of a CO_2 column and the increased reservoir pressure due to CO_2 injection

Knowledge of the reservoir is essential for assessment of total storage capacity and simulations necessary to plan the best procedures to inject CO_2 most effectively and safely through time.

The geometry of the succession sedimentary strata around the proposed site is essential, and has to be outlined semi regionally from 2D/3D seismic data. Uniformly dipping strata or prograding clinoforms above the reservoir level, which subcrop at or near the surface or seafloor, represent the most unfavourable geometric settings.

All available information about the reservoir and its overburden should be described and numerical data should be given in order to outline Digital Reservoir Geology Models (Table 3). Simulation models should be based on these models, and various plans for CO_2-injections. Simulations should visualize both the most optimistic and pessimistic scenarios of CO_2 storage.

Geological characterization prior to CO_2 injection should focus on the identification of structural and stratigraphic traps, potential leakage along faults or fractures or thief zones, and on the quantification of parameters relevant for injection of CO_2.

Satisfactory geological characterization of the storage reservoir and its overburden during the site characterization phase should produce information on reservoir structure, stratigraphy and physical properties. The datasets necessary for a robust characterization of reservoir and overburden are:

1) A regular grid of 2D seismic data of a sufficient area to characterize broad reservoir structure and extents.
2) A high quality 3D seismic volume over the injection site and adjacent area, tuned if possible, for satisfactory resolution of both reservoir and overburden.
3) Sufficient well data to permit characterization of reservoir and overburden properties.

The development of 3D seismic and more advanced drilling techniques, e.g. deviation holes and horizontal drilling, have during the last decades increased the production from other stratigraphic traps and combined trap types.

Experience so far have concluded that the 2D and 3D seismic surveys constituted the datasets which were essential for delineating the reservoir limits, its structure and the stratigraphical correlation. In most cases older datasets were adequate for mapping reservoir limits and its structure. More recent datasets enabled more accurate assessment of stratigraphical relationships both within the reservoir itself and at the reservoir/top seal interface (Chadwick et al. 2006).

Because regional reservoir mapping is relatively insensitive to data quality, cheaper, older datasets may offer good value for the money. However, the same would not apply to 3D data around the injection point. Careful assessment of data and requirements is recommended prior to purchase or acquisition of data.

7. CONCLUSIONS

The caprock should not experience serious dissolution caused by carbonic acid during the long-time storage. Ideally the reservoir rocks should be inert to reactions with injected CO_2. In a pure quartz sandstone reservoir this is close to being the case. Faults may be reactivated due to future tectonic activity, i.e. associated with volcanoes, isostatic rebound, nuclear explosions etc. The type of neotectonic activity in an area proposed for storage of CO_2 needs to be assessed.

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APPENDICES

APPENDICES

Appendix A. Assessment of reservoir fractures - Verification Checklist

Reservoir types according to Nelson (2001, p. 101):

Type 1: Fractures provide the essential reservoir porosity and permeability.
Type 2: Fractures provide the essential reservoir permeability.
Type 3: Fractures assist permeability in an already producible reservoir.
Type 4: Fractures provide no additional porosity or permeability, but create significant reservoir anisotropy (barriers).

Positive reservoir attributes in

Type 1:

1. Drainage areas per well are large
2. Few wells needed in development (in-fill for rate acceleration only)
3. Good correlation between well rates and well reservoirs
4. Best wells are often early
5. Generally high Initial Potentials (IP)
6. Can produce from non-standard and non-reservoir quality rocks

Type 2:

1. Can develop low permeability rocks
2. Often higher than anticipated well rates
3. Hydrocarbon charge often facilitated by fractures

Type 3:

1. Reserves dominated by matrix properties
2. Reserve distribution fairly homogeneous
3. High sustained well rates
4. Great reservoir continuity

Problems related to fractured reservoirs (Nelson 2001, p. 108)

Type 1:

1. Often a rapid decline curve
2. Possible early water encroachment
3. Size and shape of drainage area is difficult to determine
4. Reserve calculations difficult to constrain
5. Many development wells add rate, but not additional reserves

Type 2:

1. Poor fracture and matrix porosity communication leads to poor matrix recovery and disastrous secondary recovery
2. Possible early water encroachment (production rates may need to be controlled)
3. Fracture intensity and dip critical
4. Development pattern must be tailored to the reservoir
5. Recovery factor difficult to determine and quite variable
6. Fracture closure in over-pressured reservoirs may occur

Type 3:

Highly anisotropic permeability

2. Often unusual response in secondary recovery
3. Drainage areas often highly elliptical
4. Often interconnected reservoirs
5. Correlation between log/core analysis and well test/performance often poor

Type 4:

1. Reservoir compartmentalization

2. Wells under-perform compared to matrix capabilities
3. Recovery factor highly variable across the field
4. Permability anisotropy opposite to other adjacent fractured reservoirs of other fracture types

Checklists such as these presented below are important in early evaluations and in structuring evaluation programs. The reader is encouraged to investigate the use of these and other checklists of their own design (Nelson 2001, p. 246).

Part 1. Check Diagram for possible need for in-depth quantitative study of fractures in reservoirs.
(For example, if the fracture system accounts for only 10 percent of the total permeability and 1 percent of the total pore volume of the reservoir, the analyst may choose to neglect the system in further study. Conversely, if the fracture system provides 80 percent of the permeability and 50 percent of the total pore volume, an in-depth quantitative study of fractures in the reservoir is indicated.)[1]

Diagram 1. Total reservoir permeability due to fractures plotted as a function of fracture width, fracture spacing and matrix permeability. (Plot Fracture width (e) in cm vs. Fracture permeability (Kf) to get amount of total permeability in reservoir (Kfr) due to fractures (Kf)

Diagram 2. Total reservoir volume due to fractures plotted as a function of fracture width, fracture spacing and matrix porosity. (Plot Fracture width (e) in cm vs. Fracture porosity (φf) to get amount of total porevolume due to fractures (φf).

Part 2. Procedure for Fracture Quantification (Nelson 2001, Appendix B, p. 277)
1. Document fracture presence
    A. Logs
    B. Cores
    C. Anomalous flow rates
2. Determine if structure is present
    A. Seismic, gravity, magnetics
    B. Structure maps
    C. Dipmeters
3. Determine lithologic control of fracture distribution
    A. Logs
    B. Cores
    C. Logs and flow tests/DST's
4. Document fracture system geometry
    A. BHTV
    B. Cores
    C. Predictions (including relevant outcrops)
5. Document fracture morphology
    A. Cores
    B. BHTV-video
    C. Predictions (including relevant outcrops)
6. Determine fracture type (origin)

1

A. Application of observations to empirical models using data from (Procedure Steps 1-5 in Nelson (2001, p. 278)

7. Predict fracture distribution/extent
   A. Extrapolation using fracture type observations
8. Estimate fracture spacing and spacing variability
   A. Cores
   B. BHTV
   C. Predictions (including relevant outcrops)
9. Estimate fracture width
   A. Laboratory data
   B. Flow test data
10. Estimate reservoir properties at depth
   A. φm, Km
   B. φf, Kf
   C. Using data from (Procedure Steps 7-9 in Nelson (2001, p. 278)

Depending on what data is available from Procedure Step 6 in Nelson (2001, p. 278:

11. Estimate fracture/matrix interaction
   A. φf/φm interaction
   B. Kf/Km contrast
12. Correlate small-scale petrophysical properties with large-scale reservoir engineering tests

13. Determine fractured reservoir type

Correlate matrix and fracture properties and their communication to determine relative contribution of the fracture system and potential recovery problems

14. Make conclusions relevant to the type of evaluation
   A. Early exploration evaluation
   B. Estimation of economic potential
   C. Recovery planning and reservoir modeling.

Appendix B. Types of Reservoirs and Reservoir Properties

It is necessary to characterize the reservoir structure on both local and regional scales to elucidate CO_2 migration patterns and bulk storage potential. Studies should include:
1) structural (e. g. isopach) mapping of depth to top reservoir,
2) reservoir thickness, and
3) reservoir structural features.

When the general architecture of the storage system is established, lithological and petrophysical data from wells are essential in determining relevant properties of the reservoir. Lateral and vertical stratigraphical and hydraulic properties of the reservoir has to be assessed as these control the evolution of the CO_2 plume. The presence of stratigraphical reservoir compartmentalization is crucial input to reservoir flow models. Facies interpretations with respect to homogeneity and possible structural compartmentalization and especially variations in the sand/shale ratio, control the number of required injection wells, specifications related to the CO_2 injection, and the overall performance of the reservoir. The structural and stratigraphical detail revealed around the injection point based on geophysical data is essential to understanding and predicting the long-term behavior of the CO_2 plume. A systematic analysis of fractures and faults based on core examinations (e.g. calculated RQD index), can provide useful information to assess general hydraulic parameters in some reservoirs. In addition to the physical properties of the reservoir, its mineralogical and chemical properties are essential for robust geochemical modeling. Detailed geochemical and mineralogical analysis is essential to predict likely reactions between dissolved and gaseous CO_2, the reservoir rock, and saline fluids within the reservoir. For the reservoir, the amount of minerals which are reactive with CO_2 is relevant to predicting possible changes in porosity and permeability and also the potential of the reservoir to fix CO_2 more or less permanently as precipitated carbonate minerals.

Knowledge of reservoir properties, such as porosity and permeability (see Section 8.2.4), is required to quantify potential storage capacity and likely migration paths and rates. To determine these properties, the importance of having core material from the reservoir close to the injection point cannot be overemphasized. Core material and cuttings from additional wells will further improve characterization, particularly if vertical and lateral reservoir heterogeneity is suspected. It should be noted that, taken in isolation, samples of cuttings of reservoir sand are likely to be unrepresentative of the formation as a whole. It is far better to have one or more cores, augmented by an evenly distributed selection of well logs to obtain reliable reservoir properties. Reservoir material sampled from the likely CO_2 migration pathways, e.g. the top of the reservoir are of particular importance.

As an example, both net-to-gross ratio and porosity for several reservoir zones within a reservoir sand can be determined based on wire-line logs from half a dozen wells. Permeability can be estimated from experience with other rocks of similarly high porosity.

Analysis of core samples from the reservoir should be prioritized according to the requirements for creating an adequate transport and reaction-transport model of the reservoir during injection, and includes:

1) Sedimentology, petrography, fabric
2) Optical microscopy (optical porosity)

3) Scanning Electron Microscopy (SEM)
4) Mineralogy
5) X-ray Diffraction (XRD)
6) Particle-size analysis
7) Petrophysical / rock physics properties
8) Absolute and relative permeability
9) Porosity
10) Mechanical and thermal properties
11) Acoustic/elastic properties
12) Reservoir-water-CO_2 chemical properties
13) Pore water analysis
14) Dissolution/precipitation reactions

In order to extrapolate effectively from the cored point(s) it is necessary to have geophysical log data from wells at least as far from the injection point as the predicted CO_2 migration, which are suitable for physical property determination. Wherever possible, outcrop information should be incorporated into the characterization process. Outcrop correlatives or analogues are most valuable in understanding the nature of medium- and small-scale spatial variation in reservoir properties, and geostatistical or stochastic methods of 3D reservoir model building may be useful (Avseth et al. 2005).

The amount of information needed to characterize the reservoir varies with type. Thus, in practical terms the fairly sparse cover of wells may appear sufficient to characterize the reservoir adequately in terms of broad stratigraphy, but also predicted fluid flow behavior in the CO_2 plume.

In some reservoirs physical properties can be mapped in 2D (i. e. x, y, value) across the entire reservoir unit. In other reservoirs, physical properties may vary more significantly and information from more wells might be required to define the variability and to assess whether it is systematic or random. In some cases a full 3D reservoir property model (i. e. x, y, z, value) might be required. If so, an understanding of the environment of deposition of the reservoir is important as this will provide geological models for the likely distribution of different lithologies and therefore lateral variations away from boreholes. Establishing a good geological model relies both on the interpretation of borehole data (i. e. core samples, cuttings, logs) (Sheriff 1976, Nelson 2001) and on seismic (sequence) stratigraphic and structural analysis (Payton (ed.) 1977, Sheriff 1981, Weimer and Link (eds.) 1991, Bally (ed.) 1987, Boggs 2001). The latter may also provide specific details on the presence and geometry of internal migration barriers, e.g. shaly units on clinoforms in deltaic successions which represent an abrupt change in the sand/shale ratio (Castagna1993, Avseth et al. 2005). The effect of internal flow barriers (either dipping or horizontal) on CO_2 migration could be substantial in altering the migration path from the injection point to the top of the reservoir.

The reservoir is characterized by
1) Reservoir rock lithology
2) Porosity and permeability
3) Mineral framework and pore fluid chemistry
4) Reservoir temperature and fluid pressure
5) In situ stress and rock mechanics evaluations
6) Reservoir size and the most likely storage capacity

A necessary step in characterizing a potential storage reservoir is to estimate the extent of the likely storage footprint. Depending on the geological setting, the storage footprint will be controlled by several parameters such as the existence of a trap, the amount of CO_2 to be injected, likely migration paths and migration velocity of free (gaseous, liquid or supercritical) and dissolved CO_2, and the resulting pressure increases due to the injection. Based on the overall geological setting of a given reservoir, the likely lateral and vertical spread of the CO_2 needs to be predicted and estimated.

Typical traps for underground CO_2 storage are similar to those found in reservoirs containing oil and gas, in that the buoyant fluid of interest is kept in place due to the presence of a seal that partly or completely inhibits migration of the fluid out of the trap. The trap is the element that holds the oil and gas in place in a pool. The trap is partially due to fluid pressure gradients that exist in the reservoir fluids. The trap is the shape of the reservoir rock together with its pore space. Conceptually, there are five different types of traps or combinations of these: 'Anticline' and 'Fault' are structural traps primarily controlled by the presence of folds, faults or salt diapirs, whereas 'Pinchout', 'Unconformity' and 'Reef' are stratigraphical traps found where there are lateral permeability barriers due to sedimentological facies contrasts (Fig. B 1, see Caldwell et al. 1997).

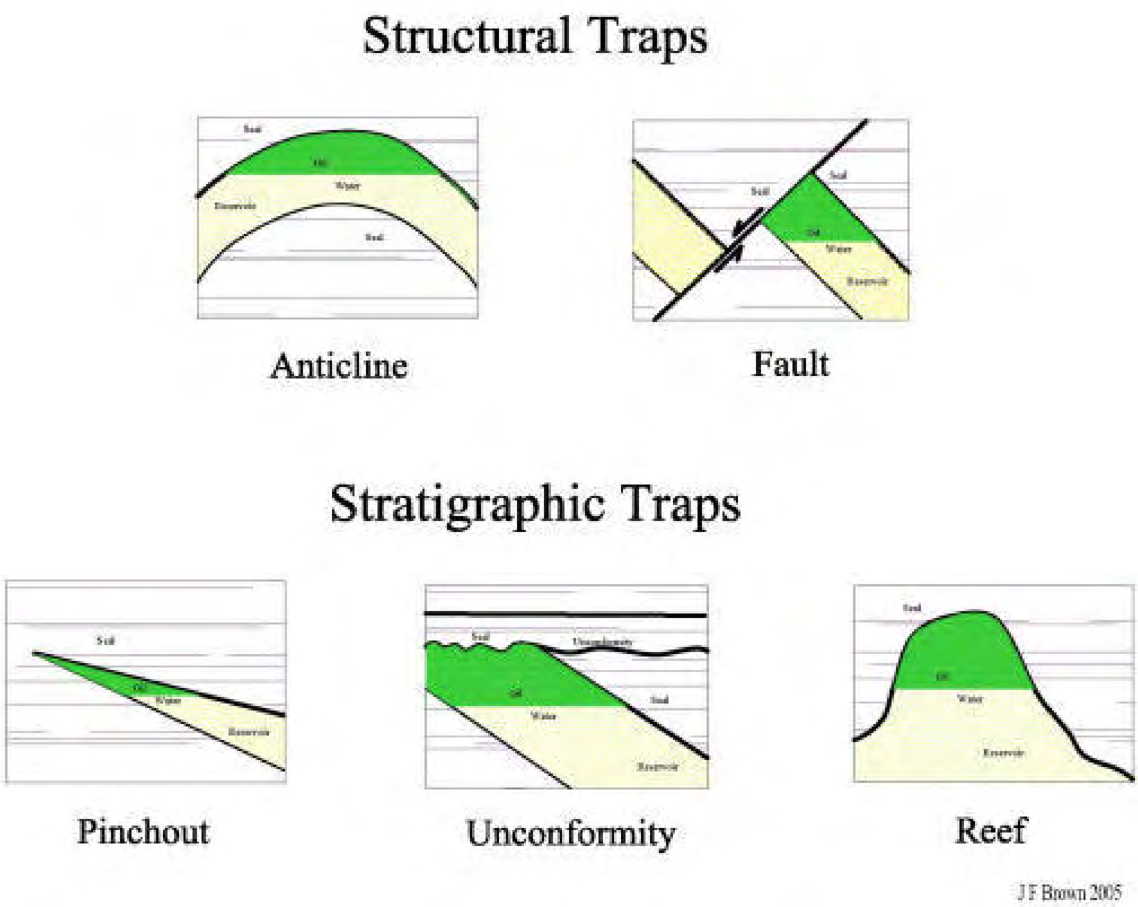

Fig. B 1 *Illustration of the five different types of* **CO_2** *storage geometries (http:// Brown 2005, see Caldwell et al. 1997).*

In general, we can distinguish between two basic storage geometries for CO_2 in the subsurface:

B.1. Structural traps

The **structurally closed reservoir**, whereby free CO_2 is held buoyantly within a distinct subsurface volume, e. g. an anticlinal trap, spatially limited by impermeable rocks surrounding the top of the CO_2 accumulation. A number of different traps with defined closure occur; structural, stratigraphic and combined geometric settings (Fig. B 1).

Structural traps, which are by far the most common for hydrocarbon fields (80%, 1962: Man's Physical World) can be formed by folding or faulting. Usually the trap is characterized by an impervious caprock which is overlying and sealing a porous and permeable rock which constitutes the reservoir. The upper boundary of the reservoir is the caprock and the lower boundary the water-oil, water-gas or water-CO_2 contact. The contact will be levelled if fluids are static or stagnant and tilted if dynamic.

B.2. Stratigraphical traps

A different type of storage site is a deep, saline aquifer with slightly dipping beds, such as the Utsira Formation of Miocene-early Pliocene age in the North Sea (Fig. B 2).

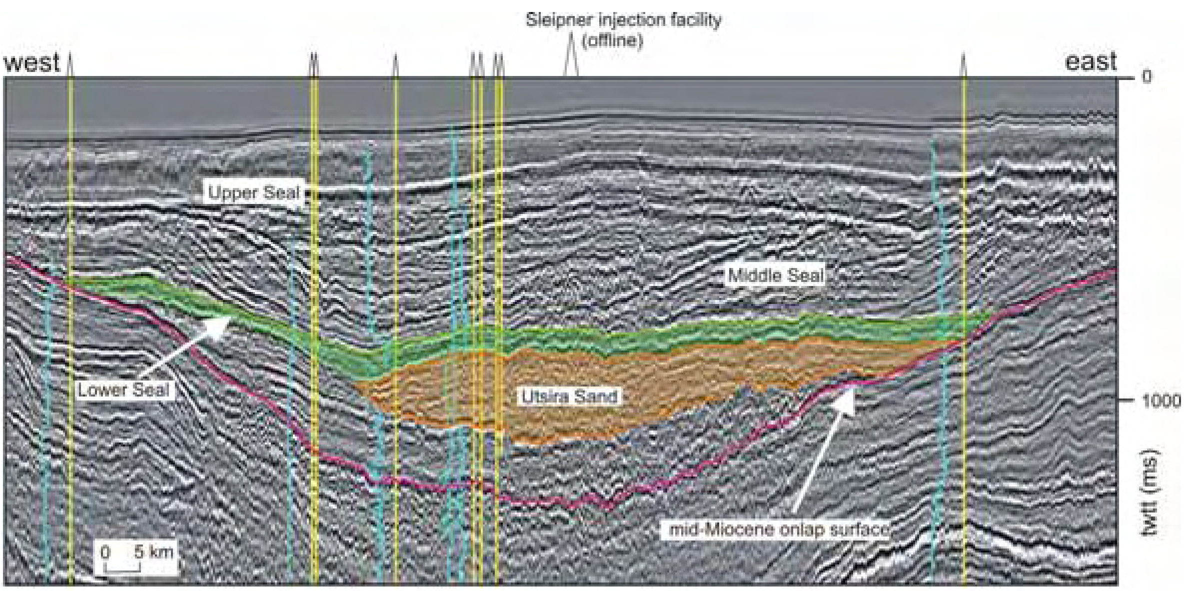

Fig. B 2 *Vertical cross-section showing seismic data from the subsurface at the Sleipner field in the Norwegian North Sea (Chadwick et al. 2006, fig. 3-9, p.31)*

This storage site is not recognized by a specific trap. A reservoir with no or poorly defined geometric closure is termed an **open reservoir or aquifer**. This may have a wide regional distribution (e.g. the Utsira Formation). An open reservoir rock may be a potential storage location for CO_2, if the caprock and/or the sedimentary succession above prevent migration to the surface. This is a result of stratigraphic traps which are due to changes in porosity occurring in clastic, carbonate or reef rocks. In the so-called **open reservoir or aquifer**, CO_2 may spread laterally, largely unhindered, assuming there are no lateral flow boundaries within the reservoir. Injected CO_2 can initially migrate upwards driven by buoyancy until it reaches the reservoir seal beneath which it can spread laterally. Accordingly, a large contact area with surrounding formation waters is created which facilitates CO_2 dissolution processes, a very beneficial storage process.

The potential for storage of CO_2 in an open reservoir or aquifer depends on volume of the aquifer matrix, its porosity and permeability and boundary conditions, which are all a result of the sedimentary environments that existed during deposition (Selley 1982). The sedimentary environment of a succession of sedimentary rocks refers to the place of deposition and to the physical, chemical and biological conditions under which they were formed. These range from glaciated terrains through alluvial fan and dune environments of desert regions, alluvial belts and lakes of low-lying valleys, the numerous environments – bay, lagoon, beach, and barrier island – of coastal areas, and finally to the great array of marine environments grading from shelf and slope to deep ocean basin (Reading 1978), see Fig. B 3.

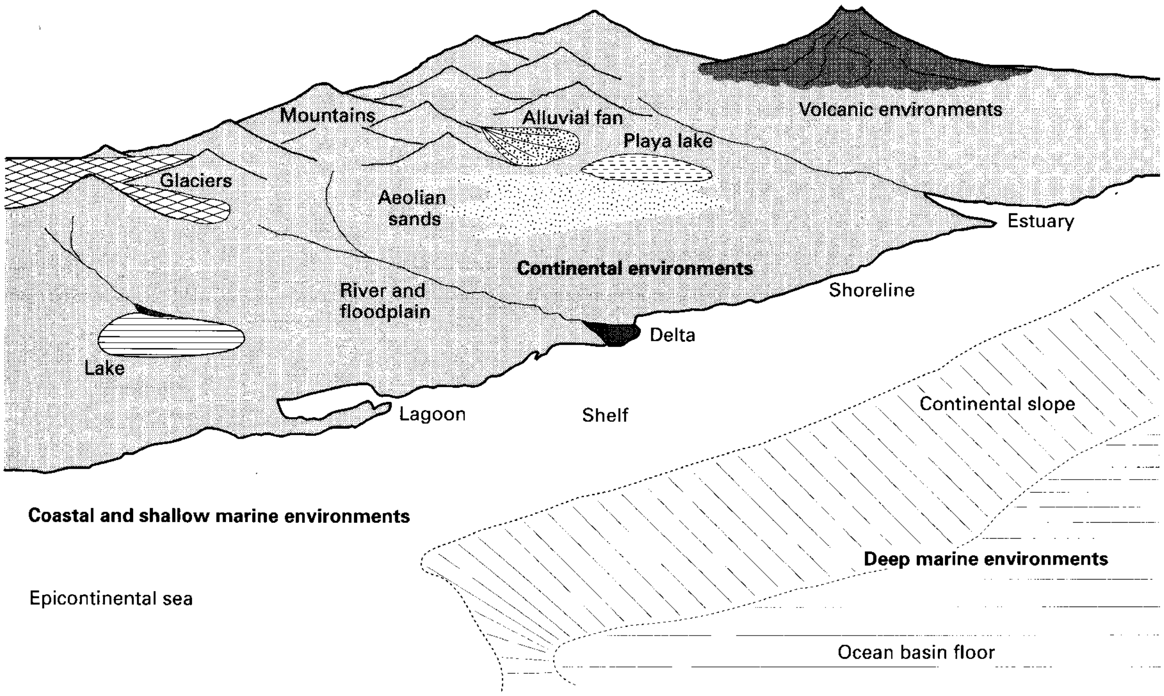

Fig. B 3 *Depositional sedimentary environments from mountains to the sea (Reading 1978)*

Various sedimentary environments are characterised by different sedimentary [2]facies of rocks of the same age as illustrated by a vertical cross-section through a basin of deposition in which sandstones (A) are deposited near shore, shales (C) farther out, and limestones (E) farthest from the shore **(**Fig. B 4). The transition from sandstone to shale (B), and from shale

[2]. "Facies" refers to "the sum total of features, such as sedimentary rock type, mineral content, sedimentary structure, bedding characteristics, etc. which characterise a sediment as having been deposited in a given environment" (Whitten, D.G.A. and Brooks, J. R. B. 1972). Facies involves, among other things, sedimentary structure, the form of the bedding, original attitude, and the shape, thickness, variation in thickness and continuity of sedimentary units.

to limestone (D), will be gradual and there will be considerable interfingering of beds. The resultant sedimentary sequences (A-E) indicate different sedimentary facies and constitute the depositional environment.

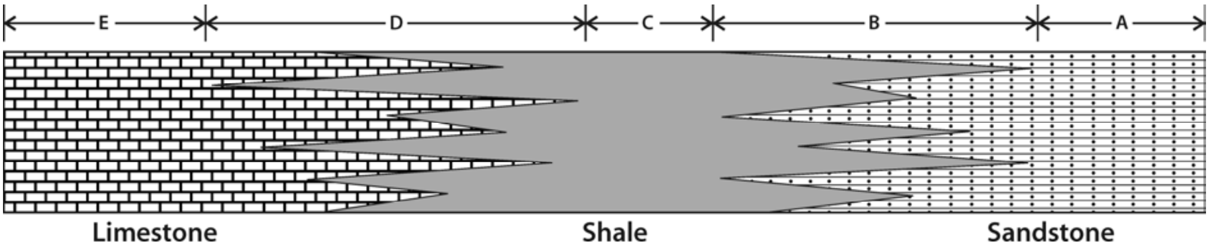

Fig. B 4 *Interfingering of sedimentary facies (from Billings 1972, fig. 9-3, p. 92).*

A more complex situation is shown in Fig. B 5, illustrating facies changes in Cambrian rocks of the Grand Canyon region, where the source area for the sediments was located to the right in the figure.

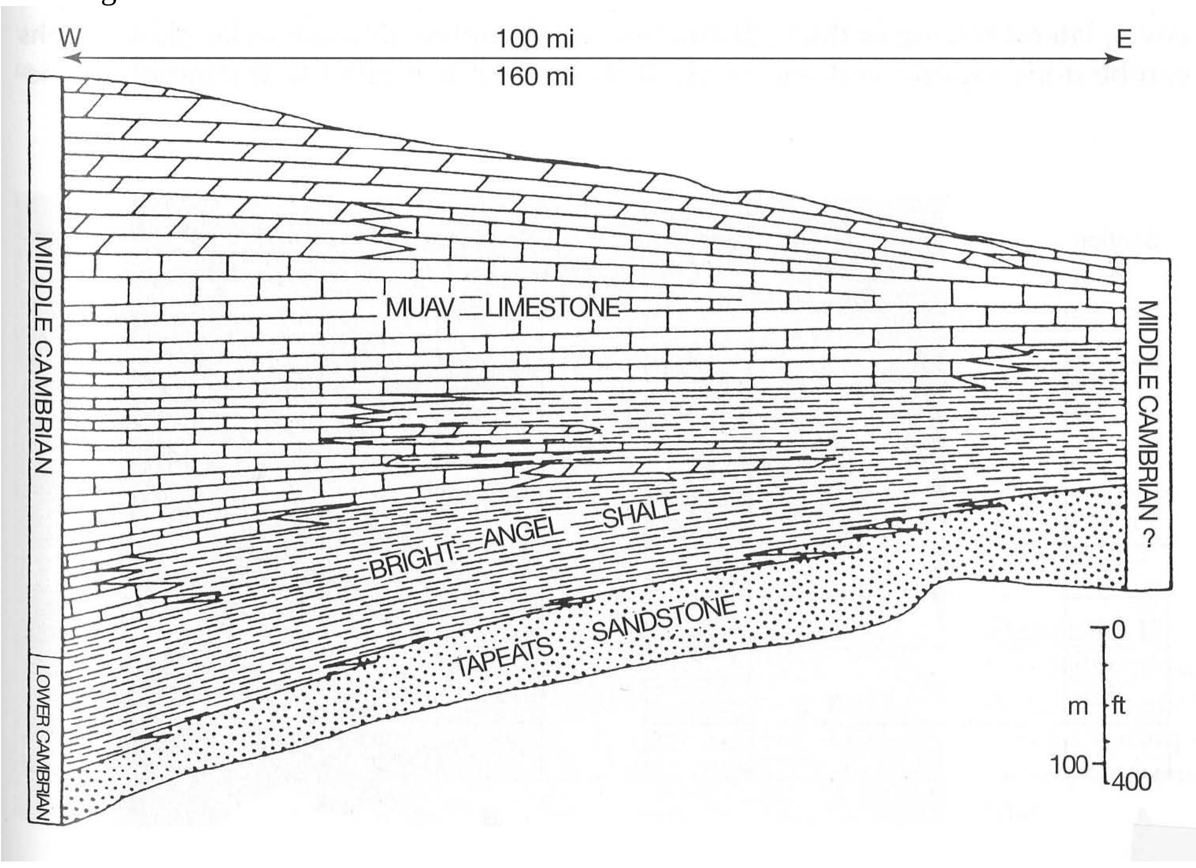

Fig. B 5 *Change in age of the basal Cambrian Tapeats Sandstone across the Grand Canyon region (from Boggs 2001, fig. 13-15, p.475, originally from McKee 1954).*

Vertical successions of facies in a borehole log or an outcrop, reflects the lateral relationships between depositional environments assuming there are no major breaks (Selley 1982). This is referred to as Walther's Law, which states that "Facies adjacent to one another in a continuous vertical sequence also accumulated adjacent to one another laterally" (1834). One of the most fruitful concepts in sedimentary geology has been the idea that patterns of facies repeat each other or that there is some cyclicity in the formation of sediments. Each facies has its own signature that may be recognized and interpreted from drill-hole cores and well-logs techniques (Fig. B 6).

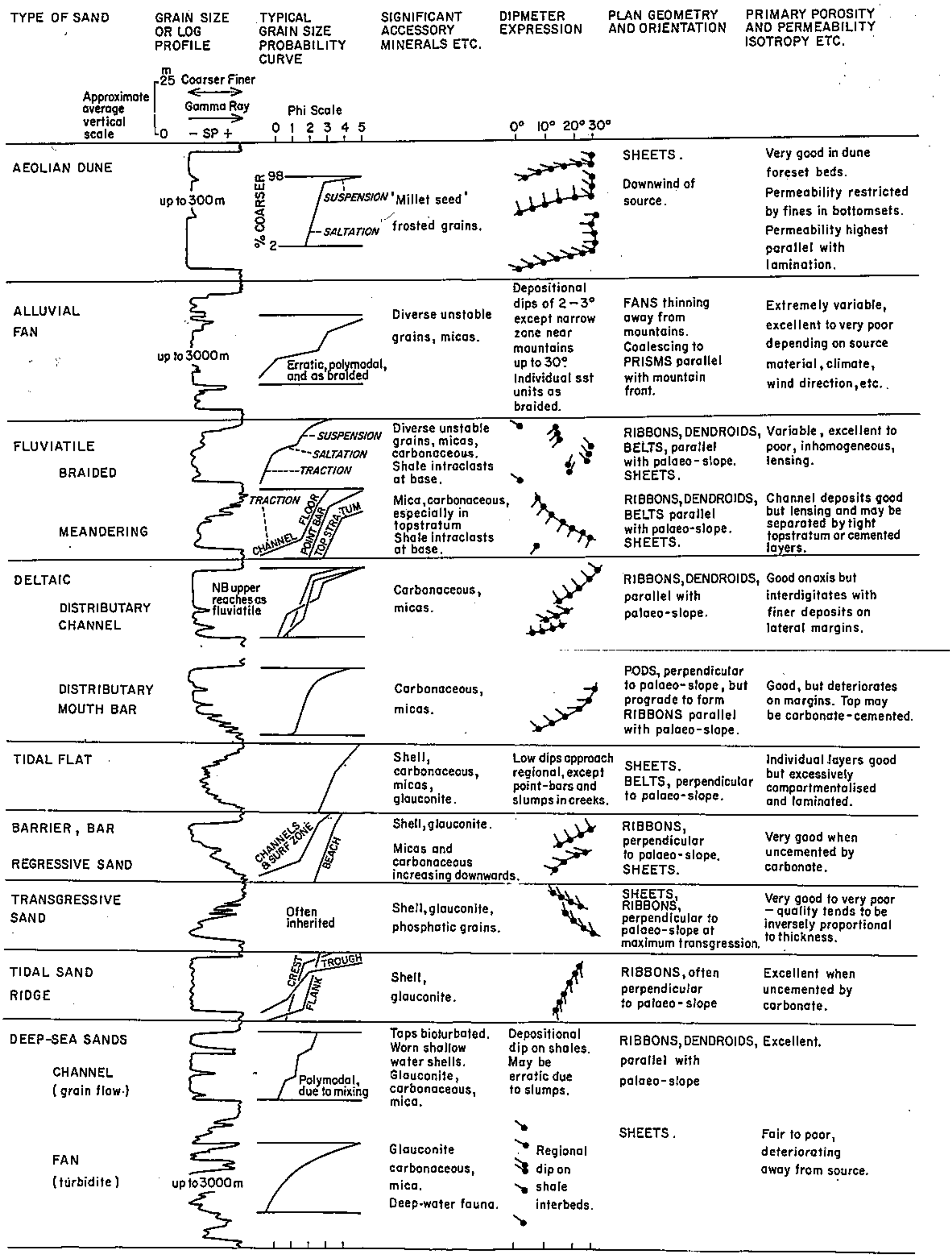

Fig. B 6 *Physical characteristics of various facies from different sedimentary environments (Taylor 1977, p.158-159).*

An example of how characteristic well-log signals are used to delineate a sedimentary rock formation is shown in Fig. B 7.

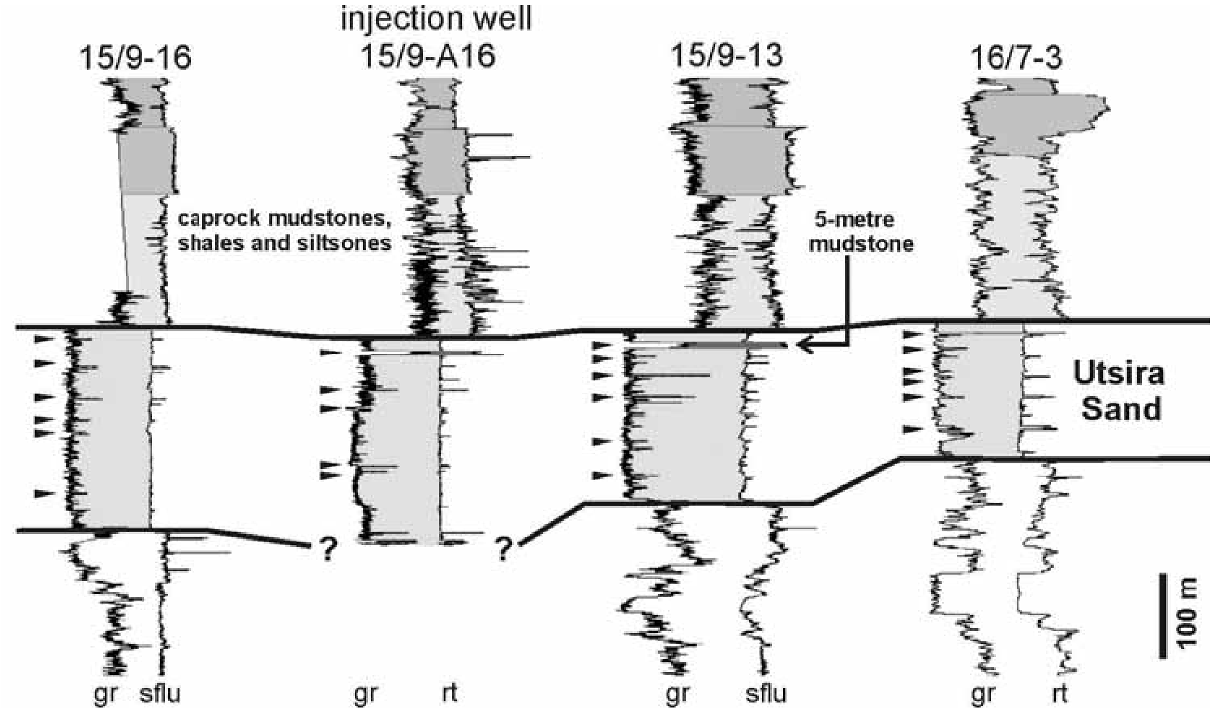

Fig. B 7 *Example on how a sedimentary rock formation, i.e. the Utsira sand, is delineated based on well-log signals (Chadwick et al. 2006, fig. 4-7, p. 92).*

A limited number of facies models have been developed each representing a particular environment. Each depositional environment can then be correlated with a single sedimentary model. In any given petroleum field detailed facies analysis of the whole reservoir is commonly available for both production and future exploration purposes. Especially if water injection has been considered or used in secondary recovery for production enhancement, a detailed understanding of variations in facies, including diagenetic changes, within the reservoir has been obtained (Fisher and McGowen 1967, Wilson and Pittman 1977).

The stratigraphic correlation of different sedimentary rock units in the subsurface are commonly done based on their similar physical properties or lithology as shown in [3]well-log signal as shown for the Utsira Sand in the Sleipner field in Fig. B 7 (Wagoner et al. 1999, Chadwick et al. 2006). Sedimentary rocks above and below have a distinctively different well-log signal. Sedimentary rocks can also be correlated based on their similar fossil content using biostratigraphical methods. In chronostratigraphy, these methods are combined with methods for age dating making it possible to correlated sedimentary rocks that are deposited more or less simultaneously.

[3] Well logs traces record variations in rock properties such as electrical resistivity, transmissibility of sound waves, or adsorption and emission of nuclear radiation in the rocks surrounding a borehole.

In [4]seismic sequence stratigraphy (Payton (ed.)1977, Vail 1987, Bally (ed.) 1987, Wagoner et al. 1988) one maps stratigraphic units separated by distinct upper and lower boundaries in the seismic reflections profiles as illustrated in Fig. B 8.

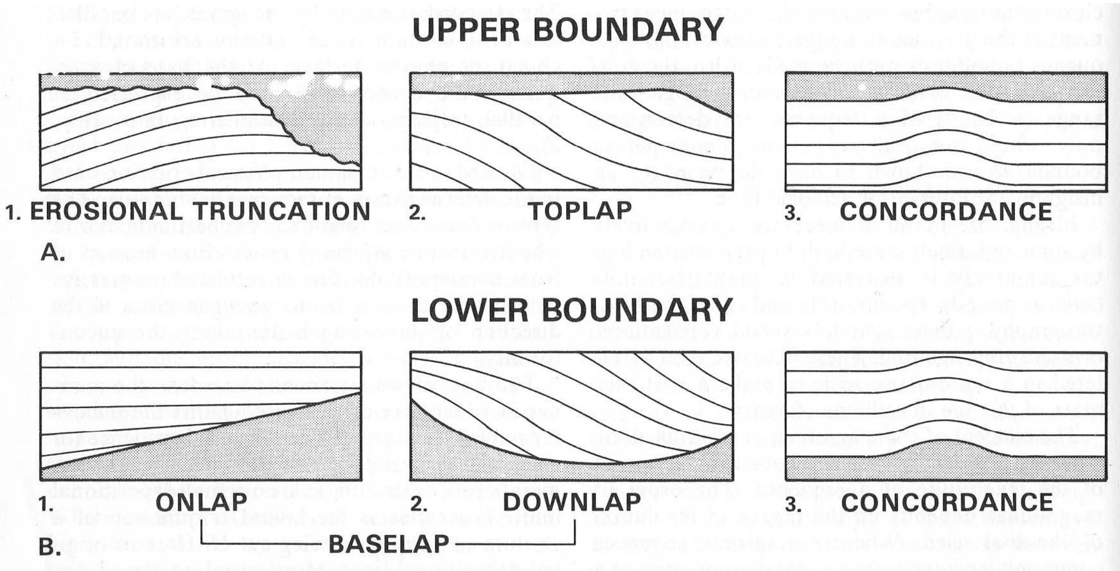

Fig. B 8 *Relations of strata to the (A) upper boundary and (B) lower boundary of a depositional sequence (from Mitchum and Vail 1977, fig. 2, p. 58).*

How these seismic facies relate to each other and their configuration, e.g. parallel, divergent, sigmoid, or oblique, in a simulated seismic reflection profile from a given depositional environment is shown in Fig. B 9. The technique of subdividing sedimentary rock on the basis of surfaces leads to a better understanding of the inter-relationship of the depositional settings and their lateral correlation. These principles have been applied in the seismic data from the Sleipner field in the North Sea.

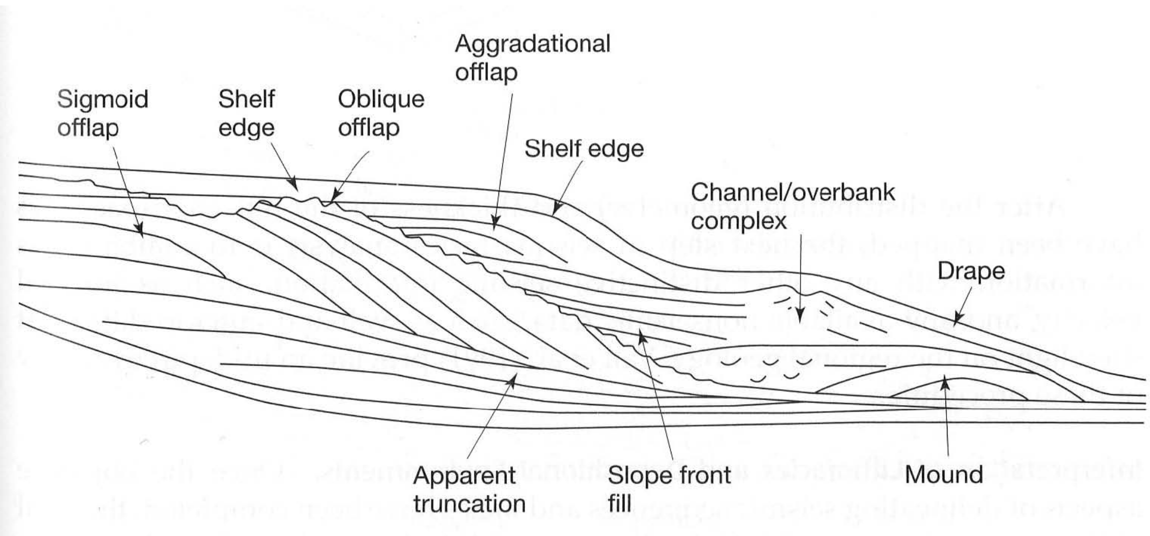

Fig. B 9 *A simulated seismic reflection profile illustrating some common seismic facies patterns that can be identified from seismic data (Visher 1990).*

[4] "Sequence stratigraphy" is the study of rock relationships within a time-stratigraphic framework of repetitive, genetically related strata bounded by surfaces of erosion or non-deposition, or their correlative conformities (Wagoner et al. 1988).

Sediments and sedimentary rocks beneath today's sea level do not necessarily have to be of marine origin; they might have formed in any of the many non-marine environments when the relationships between sea level and land areas were different. However, in area terms most of them are clastic and reef environments of the continental shelf or turbidite fan and abyssal plain environments of the deep sea, i.e. either mixed marine/fresh water or marine environments.

The relative position of sealevel to the depositional center for the sediment particles and the energy of the depositing agent, e. g. ice, water or wind, affects the dynamics of erosion and accumulation of sediments and thus the configuration of a sedimentary rock.

Thorough understanding of the effect of transgression (landward) and regression (seaward) is required. Types of regressions and transgressions are illustrated in Fig. B 10.

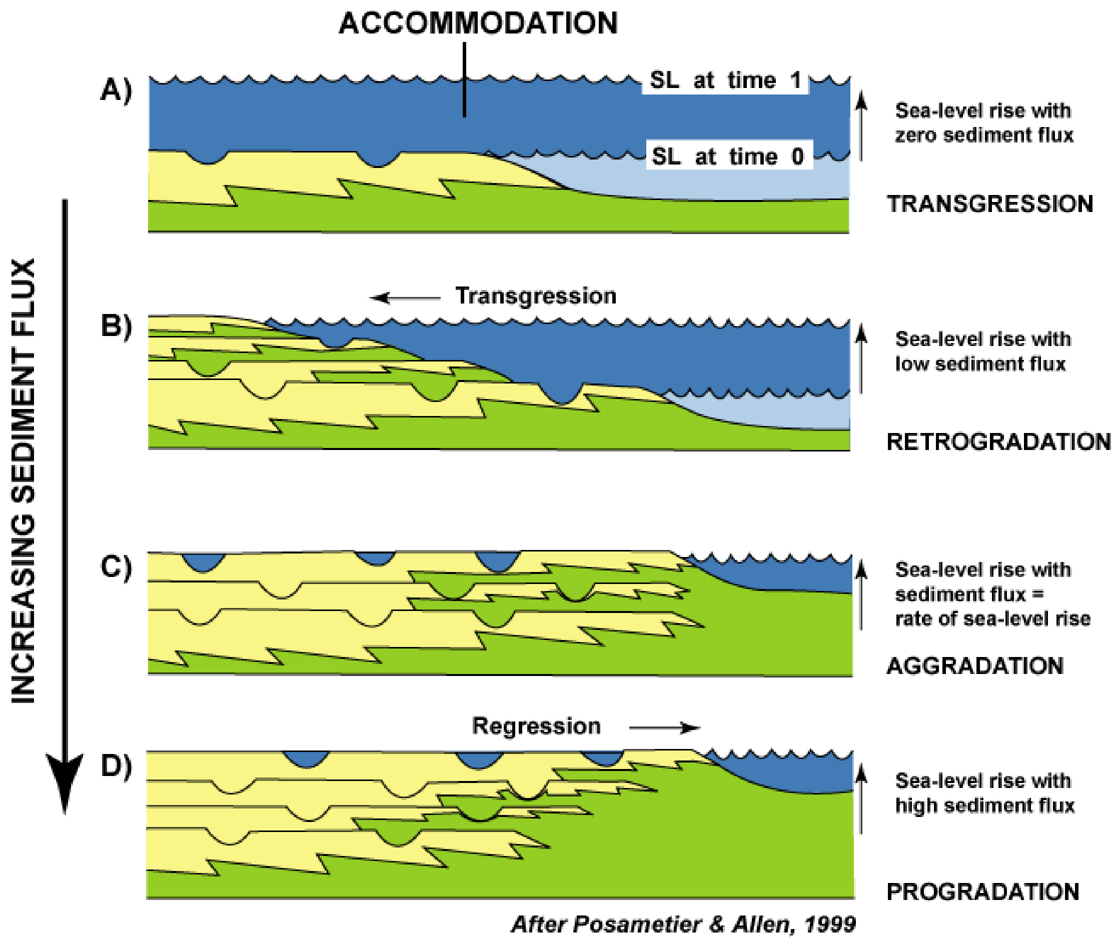

Fig. B 10 *Transgressions and regressions ranked in relation to sediment influx (http://strata.geol.sc.edu/terminology/accommodation.html)(Posamentier and Allen 1999).*

The following variables affect terrigenous deposition in marginal marine areas (Busch 1974):

A. Sinking bottom
    1. Gradual subsidence

a. Supply of sediment less than rate of subsidence
b. Supply of sediment greater than rate of subsidence
c. Supply of sediment equal to rate of subsidence

2. Cyclic subsidence
    a. Limited sand supply
    b. Moderate sand supply, abundant mud supply
    c. Limited sand and mud supply
    d. Abundant sand supply
    e. Strike-valley sand

B. Rising bottom
1. Gradual emergence
    a. Limited sand supply
    b. Moderate to abundant sand supply
2. Cyclic emergence
    a. Steady sand supply

C. Stationary bottom

As an example, many deltas (e. g. Harms 1966, Fisher et al. 1969, Busch 1971, Shannon and Dahl 1971, Busch 1974) in which large accumulations of hydrocarbons have been found, fall in category 1b. This is illustrated in Fig. B 11.

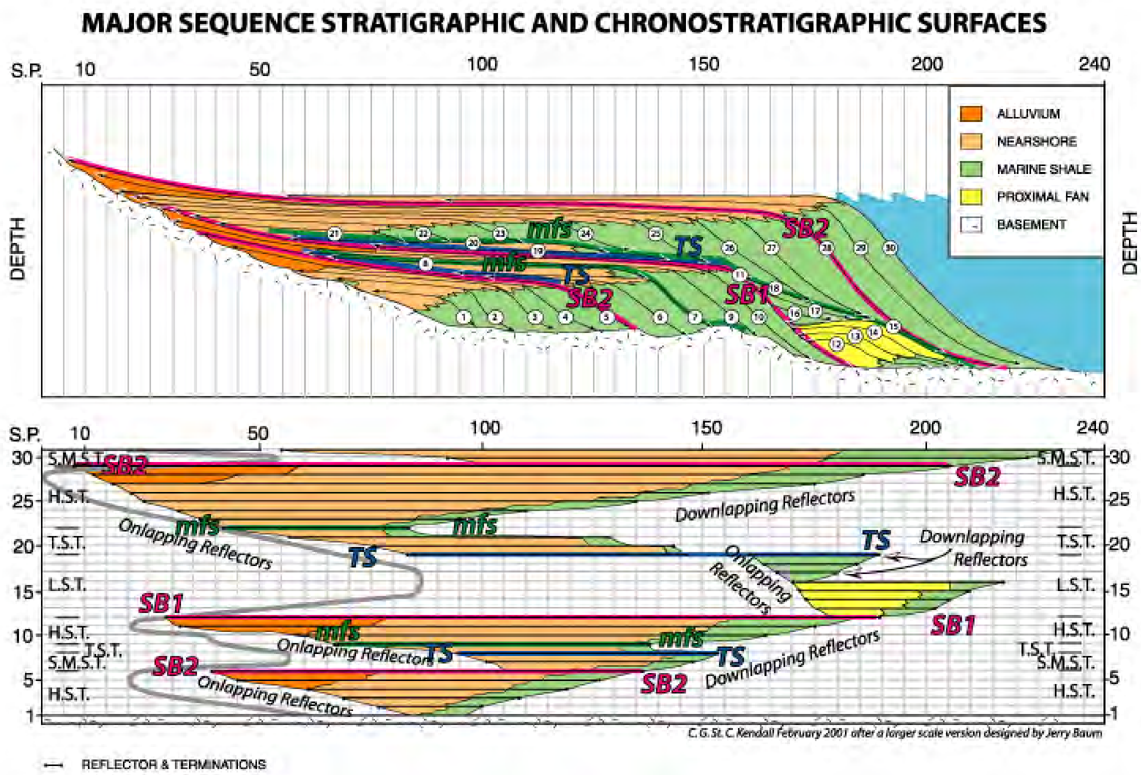

Fig. B 11 *Vertical cross-section of a delta with sediment source to the left (http://strata.geol.sc.edu/ss-chrono.html and http://strata.geol.sc.edu/exerices/chronostrat/MfsNewChronoXsecNos.pdf, Illustration by C. G. St. C. Kendall February 2001 after a larger scale version designed by Jerry Baum).*

Upon burial the sediments consolidate and the affiliated diagenetic processes, e. g. cementation, changes them into sedimentary rocks over time. The stratigraphy of a sedimentary basin, its aquifer properties, reservoir and caprocks, and potential as storage site for CO_2, reflects the relationships which prevailed during deposition. These relationships have been deciphered through the development of a depositional model of a target reservoir (Pickering et al. 1995) (Fig. B 12).

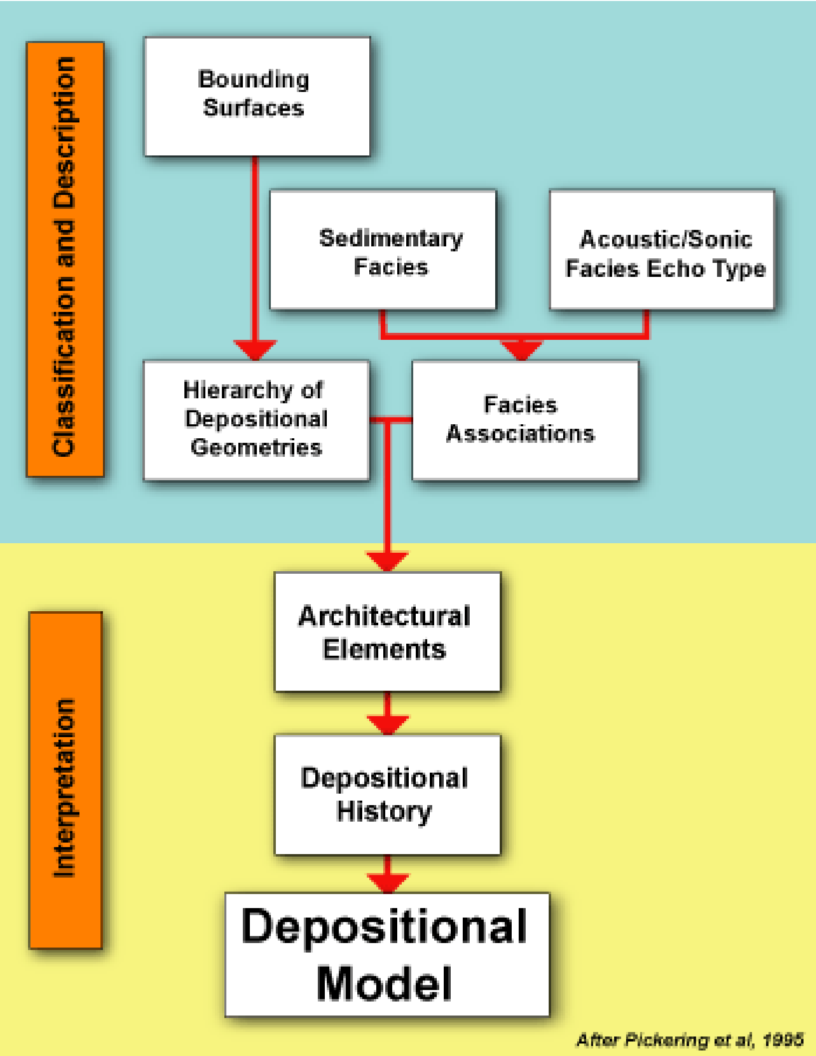

Fig. B 12 *Flow chart illustrating work path in seismic sequence- and chronostratigraphy to arrive at a geological model for the environment of deposition (http://strata.geol.sc.edu/terminology/architectural-elements.html). (Pickering et al. 1995).*

B.2.1. Closed vs. open reservoir

A major advantage of the structurally closed reservoir is that migration of CO_2 within the reservoir is tightly constrained and likely to be of limited lateral extent. This is helpful both for estimation of storage capacity and also in compulsory risk analysis. In the case of storage in a structural closure, the geometry not only of the anticlinal trap has to be assessed, but also its downdip flanks and marginal downwarps where dissolved CO_2, being denser than saline formation waters, will ultimately migrate in the longer term.

The main disadvantage of the structurally closed reservoir relate to the tall, confined columns of CO_2 that may develop, particularly if the reservoir unit itself is quite thin, resulting in strong buoyancy forces. In such cases, particular attention must be paid to the capillary sealing capability of the caprock and to its geomechanical stability. A secondary drawback is the fact that the gas-water contact is limited to a quite small contact area, thereby restricting CO_2 dissolution processes.

A major disadvantage of a large storage footprint associated with an open reservoir or aquifer, is that it requires detailed mapping of a large area to identify potential leakage pathways such as faults, but also sediment stringers, i. e. "[5]thief zones", with high permeability in the adjacent rock strata or immediate overburden. Shallow gas occurrences as indicators for previous or ongoing leakage, also require that a large area has to be monitored

B.2.2. Reservoir rock lithology

The lithology of the reservoir should be described based on drill cuttings, well logs and analyzes of cores. Tuning of base and top reservoir reflectors and interference with nearby strong reflectors or within stratigraphically complex reservoirs remains problematical. The most important seismic lithologic analysis tool beyond conventional poststack inversion is amplitude-variation-with-offset (AVO) analysis. In the presence of well control, conventional full-wavefrom AVO inversion can be a very useful technique. Azimuthal anisotropy may confound AVO analysis or even be used as a fracture characterization tool (Castagna 2001).

The most common reservoir rock type is carbonate and sandstone. These rocks have been formed in a wide variety of geological settings, and a good description of the interpreted depositional environments is important in order to assess fluid flow properties. Post-depositional alteration of the reservoir rocks must also be documented (pore space mineralization, diagenetic zones, etc.).

If CO_2 storage is planned in an active or abandoned petroleum field, most of the relevant and recommended data are probably known (wells, well logs, cores, 3D/4D seismic, production data, etc.). All experience during the production of the field will be of great value for planning of a CO_2 injection project. The effect of draining the field and compaction of the reservoir must be assessed.

If CO_2 storage in an aquifer is planned, less data exist and the degree of homogeneity of the reservoir must be carefully assessed. A fluvial plain depositional environment may for instance comprise a number of medium sized sand bodies separated by fine-grained units of various thicknesses, preventing easy migration within the gross reservoir volume. More data (wells, logs, cores etc.) will probably be necessary in order to document the gross reservoir properties. Alternatively, if the seismic data and the drilled exploration well(s) indicate a uniform reservoir lithology, an overall good reservoir performance regarding CO_2 storage may be anticipated. In that case, less additional data have to be acquired to document CO_2 storage feasibility.

Attribute maps of various seismic parameters may indicate gradational lithological changes within the reservoir. 3D seismic data will be the best bases for such evaluations. Such inferred changes of the sedimentary environment should be documented by drilling, in order to characterize the reservoir from a gross point of view (average properties of porosity/permeability).

[5] "thief zone" is zone of rocks that causes excessive fluid loss when perforated during drilling

B.2.3. Porosity and permeability

[6]Porosity and [7]permeability are the most essential parameters for the characterization of a reservoir considered for CO_2 storage.

In clastic sediments such as sandstones and shales, these parameters tend to vary with packing, grain size distribution, and diagenesis, which is a function of depositional environment and their depth of burial (Fig. B 13).

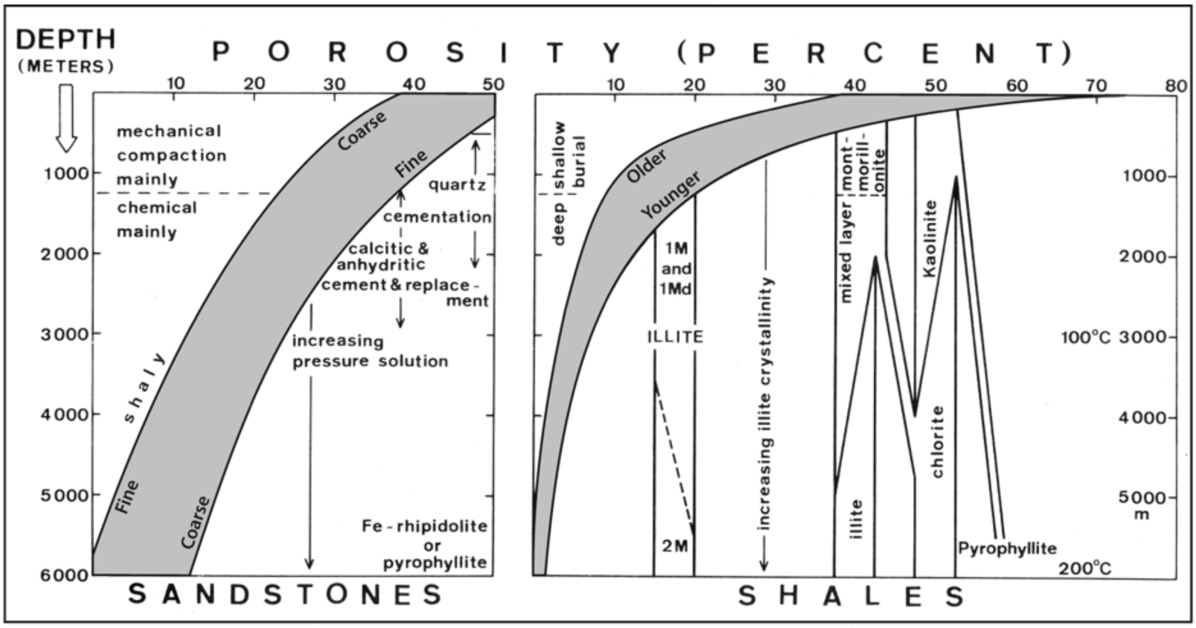

Fig. B 13 *Porosity decrease of sandstones and shales with increasing maximum depth of burial, covering the whole range of diagenesis (Füchtbauer 1978, fig. 1, p. 132).*

Most sands have porosities 30-40% shortly after deposition (Taylor 1977). In clastic rocks it can range from 3% to 30% and in carbonate rocks from less than 1% to 30% (Selley 1982). Values between 20-30% are common in reservoir sands in economic North Sea oil fields (Taylor 1977).

An objective of seismic analysis is to quantitatively extract lithology, porosity, and pore fluid content directly from seismic data (Avseth et al. 2005). The relationships between P-wave velocities and porosity in shales depending on their content of silt can be modelled based on a few samples (Fig. B 14).

[6] Porosity is percentage of bulk volume of rock or sediment which is occupied by interstices, whether isolated or connected.
[7] Permeability is the property or capacity of a porous rock, sediment or soil for transmitting a fluid without impairment of the structure of the medium (unit is millidarcy).

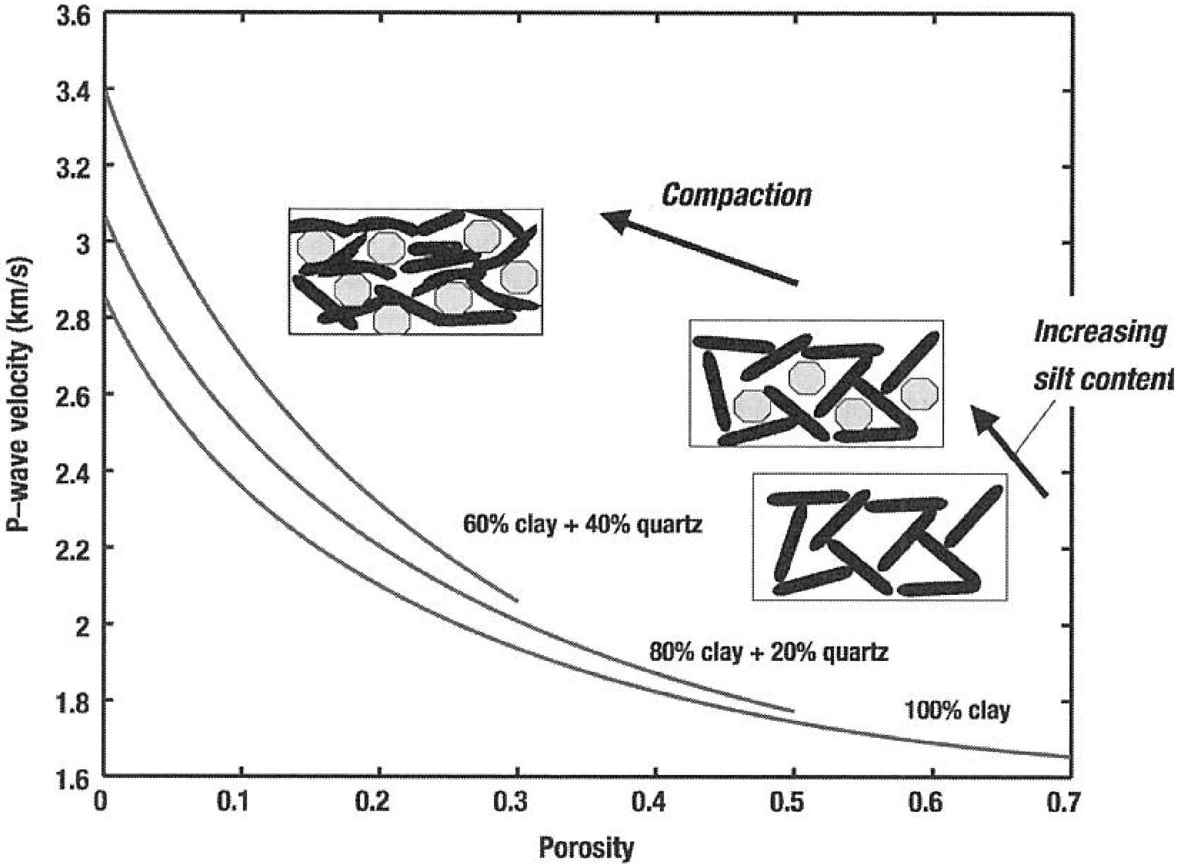

Fig. B 14 *Modelled relationship between p-wave velocity and porosity for shales with varying silt content (Avseth et al. 2005).*

However, based on testing of the porosity of a large number of samples from rock strata with known P-wave velocity in the Norwegian Sea reservoir zones, there are empirical data which establishes the natural varaiations between these parameters in the subsurface (Fig. B 15).

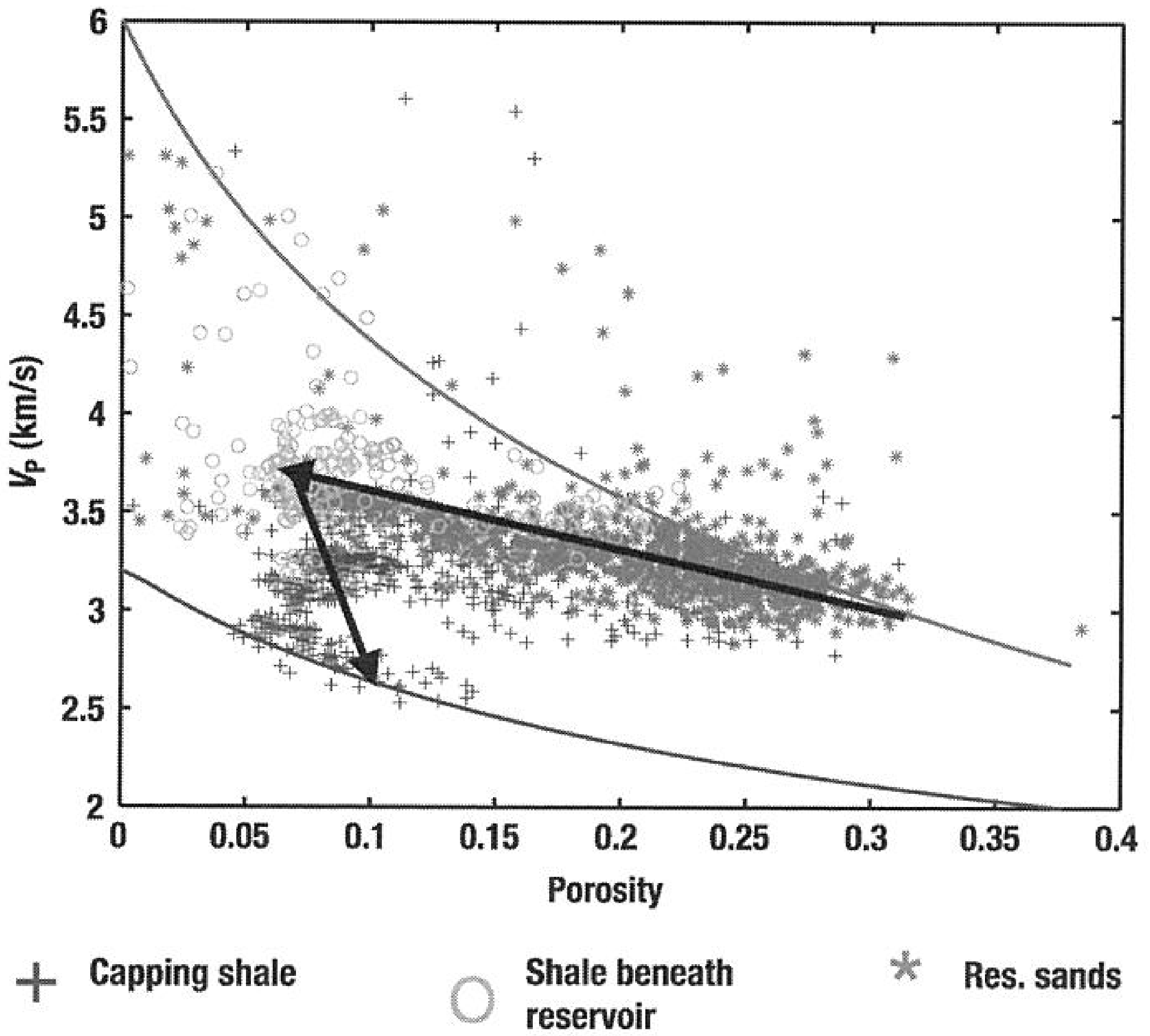

Fig. B 15 *P-wave velocity versus porosity for a Norwegian reservoir zone. Note the contrast between properties of capping shale versus shales beneath the reservoir and the reservoir sands in between (Avseth et al. 2005).*

The permeability of a sedimentary rock is the property of the porous medium to transmit fluid and is not directly related to porosity, but is a measure of how much liquid which may pass through a unit cross-sectional area, e.g. how much groundwater can pass through one square meter per unit time.

As is the case for porosity of sediments and rocks, the intrinsic permeability of rocks is due to primary openings formed syngenetically with the rock and secondary openings created after the rock was formed. The size of the openings, the degree of their interconnection, and the amount of open space within the rock are all significant.

Clastic sedimentary rocks have intrinsic permeability characteristics similar to those of unconsolidated sediments. However, diagenetic processes such as cementation and compaction may reduce the size of the throats that connect adjacent pores and thus reduce the connectivity between pores. This could reduce the intrinsic permeability substantially without significantly affecting the primary porosity. Intrinsic permeability may also be due to sedimentary structures, such as bedding planes.

Measurements of intrinsic permeability in a given sedimentary rock sample can been done by blowing air under pressure through a known volume of lab-size sample. The measured air permeability (Klinkenberg 1941) is corrected to $K_{liquid} = K_{absolute}$. However, in the subsurface, it is not only the intrinsic porosity or primary permeability that is of interest. Secondary permeability may develop in rocks by fracturing. To estimate the permability available in a given rock formation in a well, a well pumping test has to be performed. This is very resource demanding, but normally the best way to get at the efficient permeability at a given site.

In a petroleum discovery, several data sets are initially utilized in order to assess the reservoirs gross porosity/permeability (wells, a suite of well logs, cores, pressure and pumping tests, etc.). The gross reservoir porosity and permeability (p/p) is the sum of in situ rock p/p and fracture p/p. In most cases the reservoir fractures give a limited contribution to the gross porosity, but the degree of fracturing and the direction of the main fracture system may be important for modeling of the fluid flow in different drill path settings. Particularly in the case of a reservoir rock with internal layers or laminas of fine-grained sediments, the fractures may have an important contribution to the gross permeability. If a petroleum reservoir, either under production or abandoned, is planned to be utilised for CO_2 storage, all available production records will document its porosity and permeability and its fluid flow properties.

In the case that a gas reservoir in a rock of medium permeability is planned utilized for storage, an effective migration of the liquid CO_2 plume away from the injection point should be verified.

If a mapped aquifer is regarded as a potential storage site, less data exist. One well with a suite of the most relevant logs will contribute fairly good porosity data of the actual site, although evaluation of the permeability may be more uncertain. More wells, pumping - and/or injection tests is needed for fluid flow evaluations and storage capacity estimations. Preferentially, a core of the reservoir rock should be recovered in order to measure porosity/permeability and other parameters.

B.2.4. Mineral framework and pore fluid chemistry

The mineralogy of the reservoir framework is of interest regarding the mechanical strength during petroleum exploitation (collapse of the skeleton framework). Several petroleum production fields (i.e. Groningen, Ekofisk) have experienced large subsidence, interpreted mainly as a result of reservoir framework collapse.

Regarding CO_2-storage, formation of carbonic acid may dissolve parts of the skeleton framework through time if it comprises carbonates. Collapse of the reservoir may have an adverse effect also on the caprock, which may experience internal fracturing.

There are many natural waters with different chemical and physical properties that may constitute the formation waters or pore fluids, just as there are many aqueous reagents available in the chemical laboratory. When different waters are brought together and allowed to react with similar or different minerals, chemical reactions leading to dissolution may occur. Down flow of the dissolution, groundwater mixing with other types of natural waters of a different chemical composition may lead to precipitation (Runnells 1969). Depending on the textures involved and the background and bias of the observer, such processes may be termed replacement, alteration, cementation, leaching, recrystallization, mineralization, and so on. These processes are called diagenesis. An infinite number of combinations of reactants and their concentrations may occur. In order to cause diagenesis, the mixing of natural waters must result in a solution which is either undersaturated or supersaturated with respect to one or more mineral phases (Runnells 1969). Several textural changes may take place simultaneously, with one or more minerals being dissolved, while others are being precipitated .

B.2.5. Reservoir temperature and fluid pressure

Measured temperatures and fluid pressures in the reservoir should be documented. Lateral fluid pressure gradients will affect the spill point levels and the CO_2 flow within the reservoir, and will influence injection plans. A high excess fluid pressure is negative as injection of CO_2 may cause hydraulic fracturing of the caprock, and destroy its sealing properties.

Pressure and temperature information estimated for the reservoir or measured in wells in individual compartments of it can be used in the calculation of the density of the CO_2-rich phase. The geological models can be used in reservoir simulation models to explore the effects of uncertainty affiliated with different CO_2 injection strategies (number of wells, spacing, orientation, injection intervals and rates) and to predict sweep efficiencies. Efficient storage strategies should be developed in order to avoid wasting of underground storage structures and to avoid conflicts with other future options, e.g. geothermal energy utilization.

B.2.6. In situ stress and rock mechanics evaluations

Poor well bore stability, sand production, etc. are sometimes experienced during petroleum production. The understanding of such problems may be complex, including the in situ rock stresses, stress reorganization after drilling, fluid flow forces at the rock/wellbore interface and relevant rock parameters (rock strength, degree and direction of fracturing). In order to minimize the stability problems, both drilling paths and/or operational procedures are often changed.

During drilling and injection of CO_2 similar problems may be encountered, and all the experience from the exploration and petroleum production phases should be evaluated. If possible, the direction of injection drill paths should be optimal in order to obtain the most effective injection of CO_2. If storage in an aquifer is planned no such data exist, and the reservoir must be cored. Depending on the quality of the rock, laboratory rock mechanical analyzes might be necessary.

B.2.7. Storage capacity

The aim of storage capacity estimation is to confirm and refine preceeding screening studies and, to provide basic data for the predictive fluid flow and geochemical simulations the risk assessment and short/medium/long-term monitoring program design. Data is required at a variety of scales and densities, with seismic and well data being necessary to establish the structure and stratigraphy of the potential storage site at both regional and local scales. Reservoir properties can best be determined by an analysis of seismic and well log data augmented by rock material (core samples and cuttings).

After selection of one or more sites, more detailed capacity calculations are needed. Geological models of the reservoir have to be constructed as the basis for reservoir volume calculations. Porosity values obtained from logs and core samples can be assigned to the geological models in order to calculate the integral pore volume.

The total reservoir size can be calculated from the maps. The theoretical maximum CO_2 storage capacity should be calculated based on gross porosity. The actual CO_2 storage capacity is depending on a number of factors, some of them known and other estimated. Modelling and simulations are necessary, and input data should show both the minimum, maximum and most likely scenarios. The different models and input parameters should be discussed.

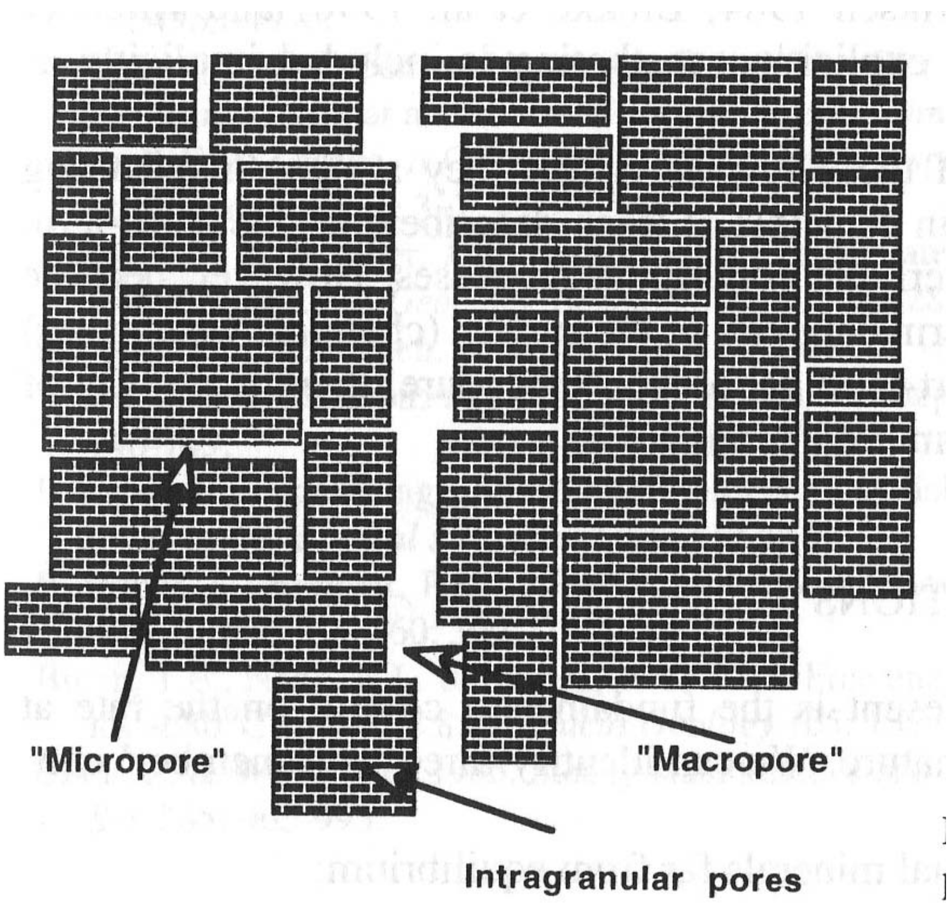

Fig. B 16 *Conceptual illustration of "microcracks" in a reservoir or aquifer (Drever 1997b)*

The degree of reactivity between CO_2, pore water and minerals will influence the long-term storage potential of the reservoir. By adding unnatural amounts of liquid CO_2 to a reservoir, formation water will be displaced as function of changes in hydraulic pressure (Fig. B 17).

However, in the fringe areas, the natural waters will be spiked with CO_2 which will hydrolyse to carbonic acid and bicarbonate, yielding a significantly different potential for diagenesis (Drever 1997a, Marini 2007). For example, instead of free CO_2 being trapped as a buoyant, mobile phase (physical trapping), reaction with formation water could trap the CO_2 as a dissolved phase (solubility trapping). Dissociation of the dissolved CO_2 will lead to the transformation of dissolved CO_2 into bicarbonate ions (ionic trapping) inducing a lowering of the pH in the formation water. Reaction of certain non-carbonate calcium-, iron-, or magnesium-rich minerals could even trap the CO_2 as a solid carbonate precipitate (mineral trapping), essentially immobilising the CO_2 for geological time periods (Bachu et al. 1994). Depending on the nature and scale of the chemical reactions, the reservoir-CO_2 interactions may have significant consequences on the CO_2 storage capacity, the injection process, and long-term safety, stability and environmental aspects (Rochelle et al. 2002a, Rochelle et al. 2002b, Czernichowski-Lauriol et al. 1996).

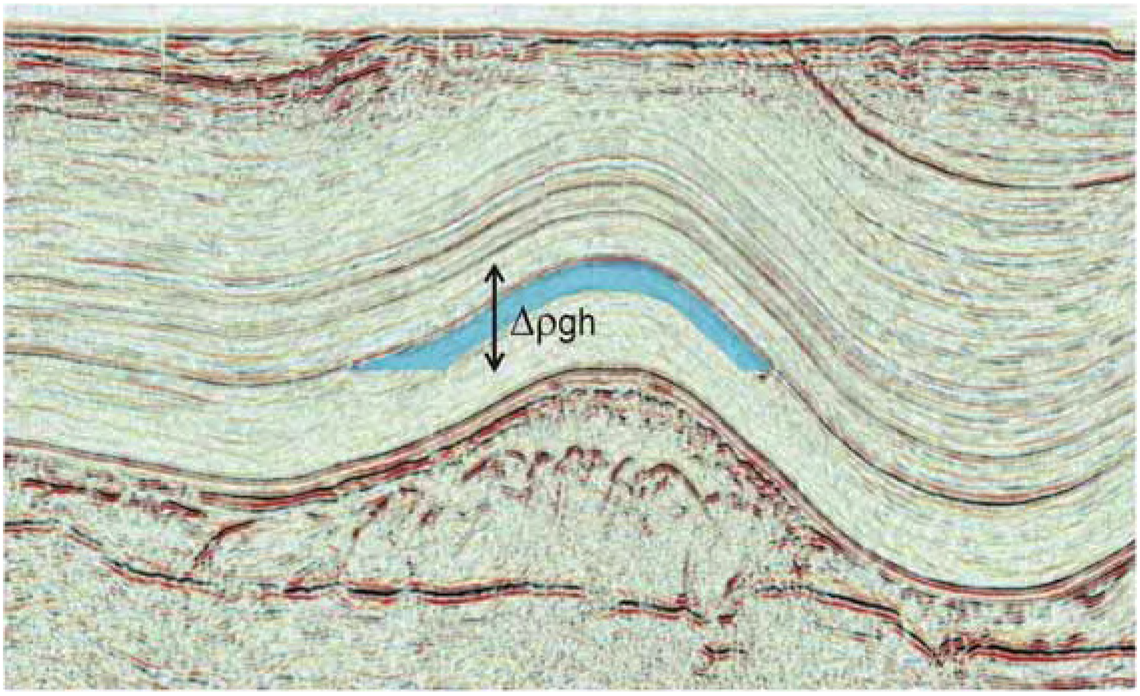

Fig. B 17 *Buoyancy forces acting on the crest of the structural closure. The blue area indicates distribution of hypothetical* $\mathbf{CO_2}$ *plume trapped in an anticline (Chadwick et al. 2006, p. 83).*

Appendix C. Caprock Properties

The whole geological succession overlying the reservoir can, for convenience, be termed the overburden and, the lower part of this which is the sealing formation directly overlying the reservoir, is called the caprock in a reservoir with closure and a roof rock in an open aquifer.

C.1. General aspects

A good caprock shall secure a safe, long-term storage of CO_2. Knowledge of the thickness and relevant parameters of the caprock, or rather the overburden, is therefore essential. Robust evaluation of the extent, nature and sealing capacity of the reservoir overburden is probably the most important purely geological element in assessing and establishing the long-term safety case for a CO_2 storage site. Particularly for the case of CO_2 storage on land, knowledge of additional reservoirs and sealing formations in the overburden is of great importance in developing a multi-barrier/multi-reservoir system of storage. The presence in the overburden of porous reservoir strata is of considerable interest as it affords the possibility of providing early warning of CO_2 accumulation at shallower depths, via seismically imaged ‘brightspots’, changes in groundwater chemistry or even changes in gravity values.

With respect to the long-term integrity of the caprock, detailed sensitivity analysis is required. The most suitable type of caprock is composed of mineralogically homogeneous, thick layers of unfaulted clays, claystones or mudstones. Capillary entry pressures should be well in excess of any likely pressure increase due to the injection process or to the buoyancy-driven accumulation of CO_2. Lithologically the caprock should not be unduly rich in carbonates since, in case of dissolution of carbonate rich layers such as marls, its sealing capacity might be significantly reduced, with local development of new migration pathways for CO_2 into overburden rocks. Accordingly, careful laboratory evaluation, in a core testing program, of capillary entry and breakthrough pressure, as well as a representative, preferably quantitative, analysis of mineralogical and geochemical composition is recommended. Microfractures may be present in the caprock due to compaction-induced hydraulic fracturing. Such microfractures may improve cross-bedding permeability substantially and thus impair seal efficacy.

C.2. Core measurements

Core measurements always relate to specific localities or points in the subsurface, and extrapolation of favourable results should be based on additional information such as analysis of cuttings or geophysical logs from other wells, before establishing a regional caprock suitability. Analysis of cuttings may give information on grain and pore size distribution, specific surface area, mineralogy and TOC (total organic carbon) that bear close relation to flow and capillary properties of the caprock. If the competancy of the caprock cannot be robustly demonstrated, the consequences of likely migration scenarios (e.g. leaking fault or leaking seal) should be analyzed as part of the site risk analysis. A number of techniques have been developed to examine the transport characteristics (e.g. intrinsic permeability, capillary entry pressure, relative permeability, dilatancy and pathway flow) of natural and synthetic materials. The choice of test methodology depends on the type of material under investigation and the parameters required for a particular study.

A laboratory or field study can often employ one or more techniques to fully quantify the transport characteristics of a particular material or formation. The main laboratory and field techniques are based on simple principles where the injection permeant is held at a constant pressure, injected at a constant flow rate or increased to an elevated pressure and then allowed to decay.

C.3. Laboratory permeability testing

Accurate characterization of very low permeability caprock strata requires extremely careful and rigorous laboratory procedures because of the very low flow rates involved.

In constant pressure gas testing, the injection pressure of the permeant is raised in a series of steps until gas entry occurs. Subsequent steps in gas pressure are used to define the gas permeability function.

In constant flow rate tests, the gas permeant is pumped into the upstream reservoir of the injection system, gradually raising its pressure until it overcomes the resistance for flow within the laboratory specimen. Once gas movement within a specimen occurs, flow rate into the injection system can be varied to examine the transport characteristics of the material, thereby defining the permeability function.

In pressure decay tests, the gas pressure is increased rapidly to a value exceeding that of the sum of capillary entry and pore water pressures, so that gas flow begins at the start of the test. Pressure in the injection system is then allowed to decay with time. The shape and asymptote of the pressure decay curve can be analyzed to yield both permeability and capillary pressure data.

The pore-pressure oscillation technique (Kranz et al. 1990, Fischer 1992, Fischer & Paterson 1992) relies on the generation of a sinusoidally varying pressure pulse in the upstream pore fluid by means of a computer-controlled servosystem. Transference of this pressure wave through a porous sample results in amplitude attenuation and phase shift when measured downstream, yielding specimen permeability. Tests can be conducted with different upstream pressure amplitudes, typically 1 MPa, and with varying periods, usually between 100 and 2000 seconds.

Constant pressure and constant flow rate tests result in a progressive dewatering of the material as gas pressure and gas saturation increases (i.e. a drainage response). In contrast, pressure decay tests result in a progressive reduction in gas saturation as gas pressure decreases (i.e. an imbibition response). The hysteresis between these two types of behavior and the time dependency of some of the processes under investigation may result in a range of values depending on the test methodology selected. A comparative study of the different testing techniques has yet to be undertaken. However, given the unique physico-chemical properties of mudrocks and diversity and complexity of their behavior, a rigorous and complete appraisal may take considerable time.

By altering axial load and/or the confining pressure, laboratory tests provide a mechanism to examine changes in transport properties during deformation. This allows transport properties to be mapped onto mechanical frameworks, such as the critical state model. The laboratory allows researchers to isolate the environmental parameters, such as pore pressure, confining pressure, axial stress, temperature, pore fluid chemistry, to fully describe the effect of each.

The selection of test methodology and subsequent design of the experimental program should be appropriate for the geological formation under investigation in order to provide data suitable for the purposes of the study. In designing a test program, care should be taken to minimize perturbations (both chemical and physical) during handling of sample material used for examination. When determining intrinsic permeability in chemically reactive formations such as clays, mudrocks and shales, drilling fluids and aqueous permeaments should be matched, where appropriate, to the properties of the interstitial fluid. Laboratory and field tests should be performed under representative conditions, with the test procedure carefully designed and documented to prevent inducing a material response that is non-representative of the natural behavior.

The most common caprocks are claystone and shales, which both have low permeabilities. The most important rock property is the vertical permeability, which is commonly much lower than the horizontal permeability due to the orientation of clay minerals and fine-grained layers/laminas which may occur.

C.4. Caprock core analysis

Analysis of the caprock core should be prioritised according to the requirements of the geomechanical and reservoir transport and reaction-transport modellers, as is the case for reservoir rocks and include:

1) Sedimentology, petrography, fabric
2) SEM (scanning electron microscopy)
3) X-ray screening
4) N_2 BET
5) Mineralogy
6) XRD (x-ray diffraction)
7) Particle-size analysis
8) CEC (cation exchange capacity)
9) TOC (total organic carbon)
10) Petrophysical and rock physics properties
11) Mohr-Coulomb behavior
12) Young’s modulus
13) Drained bulk modulus
14) Cam - Clay parameters
15) Time-dependent creep
16) Poisson’s ratio
17) Acoustic velocity
18) Capillary entry pressure
19) Permeability
20) Caprock-water-CO_2 chemical properties (cf Sections 4.3.1.1 and 4.3.1.3)
21) Pore water analysis
22) Chemical reactions
23) Physical reactions (dehydration)

C.5. Borehole and seismic data

In the SACS/CO_2STORE study (Chadwick et al. 2006) it was found that the determination of the extent of the caprock will rely on a regional spread of boreholes and on grids of 2D and 3D seismic data. Sample material should be available in the form of cuttings (for wide regional coverage) and core (for specific property testing) in sufficient quantity to undertake a detailed suite of analytical tests. The core material should ideally be in a location above the likely CO_2 migration pathway or from a demonstrably analogous position. Geophysical well logs should also be utilised to extrapolate sample parameters across the whole caprock volume.

Data derived from either whole-core samples or well testing are most reliable (Nelson 2001, p. 35). Well logs are often used (Aguilera 1980), but are not so accurate and less appropriate. When it comes to whole core samples, they should represent a relatively large volume of rock and a standard permeability analysis has to be performed in 3-D. The fracture permeability should be determined under confining pressure because open fractures are generally higher in absolute permeability than the matrix, but the fractures are much more compressible, and therefore reduce in permeability and porosity much more rapidly than the matrix with the application of force (Jones 1975, Nelson and Handin 1977, Nelson 1979, Nelson 1981).

The whole-core samples, which sample both fractures and unfractured material, can be used for selected fluid saturation or relative permeability tests. Small-scale and large scale porosity can be determined and 3-D permeability tests by well-testing should completed.

Well-testing gives a bulk response of a relatively large volume of the reservoir and a summary of the relative contribution of all its individual parts. Useful well tests are:

i. pressure transient analysis
ii. pressure pulse testing
iii. interference testing

Well-log analysis has been used successfully to delineate fracture occurrence and distribution in the wellbore (Aguilera 1995). The quantification of the subsurface reservoir properties such as porosity and permeability of fracture systems by well logs is, however, much more difficult as it gives highly variable and inaccurate results (Nelson 2001).

In the absence of core material, drill cuttings (preferably augmented by sidewall core material) are suitable for a limited range of analytical techniques such as petrography, SEM and XRD. Results from analysis of cuttings can be used to assess sealing capacity in a qualitative manner, by comparison with samples from proven oil/gas field caprocks, or semi-quantitatively. Discrepancy between capillary entrance pressures derived from core and empirical values derived from cuttings may reflect limitations of the latter method. However, it also may reflect that core samples are from a single point and may well not be representative of the caprock volume as a whole. This means that in addition to establishing physical properties at a number of point locations, such as wells, it is necessary to evaluate the bulk properties of the caprock and any structures that may affect it particularly in the vicinity of the predicted CO_2 migration paths.

Caprocks consist typically of sediments from distal depositional environments, which are characterized by relatively uniform conditions over large areas. Caprock lithology, fluid-flow and geomechanical properties are therefore likely to vary much less than those of the reservoir rocks. Consequently, extrapolation of lithology-related caprock properties from a small number of wells over a large potential footprint area (typically some tens to a few hundred km^2) can be carried out with greater confidence than extrapolation of reservoir properties. However, relevant caprock properties due to deformation by faulting and fracturing cannot easily be extrapolated, but require detailed local assessment covering the whole footprint area.

Caprocks may contain sand stringers and layers or laminas of sand parallel to the stratification. In order to reduce a potential migration along a pattern of minor paths, a minimum thickness of the caprock is required. The minimum thickness will depend on several factors (permeability, depth of reservoir, anticipated fluid pressure, etc). In any case, increasing thickness of the caprock will show an increasingly effective migration barrier. Based on 2D/3D seismic data and wells/logs, a thickness map of the caprock must be made. Simulations based on all available data will indicate the minimum thickness required for a good seal.

The regional seismic stratigraphy of the caprock should be discernible from 2D seismic data, as would major faults that cut it. Smaller structural features for example 'polygonal' type minor faults that characterize some shale sequences, generally require 3D seismic data for their proper identification. Very small structures, fractures and joints are beneath the limit of seismic resolution.

Assessment of the presence of microfractures in the subsurface is challenging because mechanical deformation and depressurisation during coring may induce microfractures in core samples that are difficult to distinguish from those that formed in situ. Consequently, careful coring and preservation of cores is a pre-requisite for successful microfracture assessment. Core analysis can be aided by numerical simulation, supported by experimental studies, of coring-induced damage and of the pore pressure evolution during compaction. Further, high-resolution well-logs (e.g FMS) may reveal the presence of microfractures in the borehole walls. Injection-induced pressure changes could lead to compromise of the caprock seal and possible geomechanical consequences should be assessed prior to injection commencing. Two main effects should be considered: fracture dilation due to increased pore-pressures and induced seismic slip due either to raised pore pressures or a reduction in normal stress due to buoyancy forces exerted by the CO_2 plume. Fracture orientations that are likely to be conducive to fluid flow or susceptible to seismic slip can be determined relative to the principal stress axes if the in situ stress is known.

The in situ caprock should not be seriously fractured due to the experienced geological stress history (doming/faulting, etc.). If an exploited petroleum reservoir is planned used for CO_2 storage, it should be documented that the reservoir skeleton framework has not collapsed and caused secondary fracturing of the caprock and/or displacements of blocks.

Sufficient mechanical strength is important if high fluid pressures are formed. In claystone and shales it is commonly a large anisotropy factor. The tensile strength is highest perpendicular to the stratification and/or foliation, and that is an advantage regarding potential hydraulic fracturing.

If possible, the in situ stress conditions should be evaluated based on all available data. Fault planes with orientations parallel/sub-parallel to the main stress field (S_{max}) is more likely to be non-sealing than faults planes oriented normally to (Ligtenberg 2005).

The inability of a caprock succession to provide a long-term seal for the underlying reservoir may be revealed by indicators of hydrocarbon migration into and through the caprock. Seismic amplitude anomalies and gas shows in the caprock may signify the presence of shallow gas. Pockmarks and vents at the seafloor are indicators of gas migration from the underground into the seawater. However, gas within the caprock may have formed biogenically in situ, and does not necessarily imply migration from below. The nature and source of shallow gas needs to be addressed if indicators of its presence have been detected. The degree of correlation between gas migration indicators based on seismic-images and mapped faults is clearly of potential importance in evaluating fault-related leakage.

The quality of the injected CO_2 may have an important impact on the geochemical interactions in the reservoir as well as on its phase behaviour. Necessary data for establishing the phase behaviour of injected CO_2 requires determination of the exact composition and the anticipated temperature of the CO_2 during injection. The impact of certain impurities can currently be assessed using existing models, but this depends on the type of impurity.

Appendix D. Key Site Initial Description Documentation

The main deliverable of the site characterization phase comprises necessary documentation to enclose with an application for permission to store CO_2 to the relevant authorities. This consists of a full technological and economical evaluation of the project including site characterization, risk assessment and short/medium/long term monitoring plan and remediation strategy.

Appendix E: Uncertainty and error evaluation

Uncertainty assessment
In order to make a decision whether to accept CO_2 storage in an underground reservoir or not, a decision maker has to make a decision based on the available information on leakage potential. This information is characterized by uncertainties of different kinds. The main subject in this chapter is to briefly describe methodologies and tools to characterize uncertainty and to assess the various sorts and sources of uncertainty, and the propagation of uncertainty through models to management information.

Definition (Uncertainty): A person is uncertain if s/he lacks confidence about the specific outcomes of an event or action. Reasons for this lack of confidence might include a judgement of the information as incomplete, blurred, inaccurate or potentially false or might reflect intrinsic limits to the deterministic predictability of complex systems or of stochastic processes (Klauer and Brown 2003).

Uncertainty is seen as an expression of the various forms of imperfection of the available information and depends on the state-of-the-art of scientific knowledge on the problem at the moment that the decision has to be made.

Subsurface property estimation from remote geophysical measurements is always subject to uncertainty, because of many inevitable difficulties and ambiguities in data acquisition, processing and interpretation (Avseth et al. 2005). The estimation of uncertainty at different steps in the process towards CO_2 storage is used to:

1. Assessing risk. Quantifying uncertainty helps to estimate risks better, and possibly take steps to protect ourselves from those risks.
2. Integrating data from different sources. Complex interpretational processes such as reservoir, cap-rock and leakage path characterization usually require integration of data from different sources and of different types. Understanding the uncertainty helps to assign proper weights before they are combined in an interpretational model such as a multiphase flow model.
3. Estimating value of additional data. Additional data may help to clear away ambiguities and reduce uncertainty – but not always. It requires quantitative estimates of uncertainty to estimate those values.

If uncertainty is recognised as being an important issue, then the most common strategy to cope with this is to use probabilities. However, the use of probabilities presupposes a number of things about the available representation of discrete leakage pathways, such as faults, fractures, thief zones and wellbores. First, it assumes that the event is properly characterized by a set of potential outcomes. Secondly, it assumes that the probabilities of each outcome are also known. We will call such a situation a risk situation, where risk is defined as damage multiplied by probability.

Example
A decision needs to be made to implement CO_2 storage in a certain reservoir or to make additional field measurements and perform modelling to improve the data basis and thereby reduce the uncertainty involved. So the decision maker believes that he can calculate the uncertainty (in terms of probability distribution function) for the occurrence of leakage pathways and the CO_2 leakage potential from the reservoir, and how much this uncertainty

will change in case of new data. At the same time, the decision maker knows the costs of making a wrong decision and the costs of the additional field program.

E.1. Type, Sources And Nature Of Uncertainty

E.1.1. Types (levels) of uncertainty

Uncertainties can be classified in several different ways according to their origin (IPCC 2007). Two primary types are ‘value uncertainties’ and ‘structural uncertainties’. Value uncertainties arise from the incomplete determination of particular values or results, for example, when data are inaccurate or not fully representative of the phenomenon of interest. Structural uncertainties arise from an incomplete understanding of the processes that control particular values or results, for example, when the conceptual framework or model used for analysis does not include all the relevant processes or relationships. Value uncertainties are generally estimated using statistical techniques and expressed probabilistically. Structural uncertainties are generally described by giving a collective judgement of experts on their confidence in the correctness of a result. In both cases, estimating uncertainties is intrinsically about describing the limits to knowledge and for this reason involves expert judgment about the state of that knowledge. A different type of uncertainty arises in systems that are either chaotic or not fully deterministic in nature. This limits for example the ability to project all aspects of climate change, but also CO_2 storage aspects are not fully deterministic in nature, which thus leads to uncertainty in assessing the risk of leakage.

An entire spectrum of different levels of knowledge exists, ranging from the unachievable ideal of complete deterministic understanding at one end of the scale to total ignorance at the other. To distinguish between various levels of uncertainty, Walker et al. (2003) employs the following terminology: determinism, statistical uncertainty, scenario uncertainty, recognised ignorance and total ignorance (Fig. E 1)

Fig. E 1 *The progressive transition between determinism and total ignorance (Walker et al. 2003)*

Determinism is the ideal situation in which we know everything precisely. It is not attainable in natural sciences, but acts as a characteristic at one end of the spectrum.

Statistical uncertainty is any uncertainty that can be described adequately in statistical terms. It can apply to any location in the model, even to model structure uncertainties, as long as the deviation from the true value can be characterized statistically. Statistical uncertainty is what is usually referred to as “uncertainty” in the natural sciences. An exclusive focus on statistical uncertainty, however, implicitly assumes that the functional relationships in the model are good descriptions of the phenomena being simulated (in our case leakage paths and CO_2 leakage from underground reservoirs), and the data used to calibrate the model are representative of circumstances to which the model will be applied. If deeper forms of uncertainty supersede statistical uncertainty, there should not be according more attention to statistical uncertainty as to other levels of uncertainty in the uncertainty analysis. The most obvious example of statistical uncertainty is measurement uncertainty associated with all data (due to sampling error, inaccuracy or imprecision in measurements).

Scenario uncertainty implies that there is a range of possible outcomes, but the mechanisms leading to these outcomes are not well understood and therefore impossible to formulate in terms of probability of occurrence.

Recognised ignorance is fundamental uncertainty about the mechanisms and functional relationships being studied. It may be reduced by conducting further research.
Total ignorance is the other extreme on the scale of uncertainty, to the extent that we do not know what we do not know. The full extent of our ignorance is not known.

Regardless of our confidence in what we know, ignorance implies that we can still be wrong ("in error"). In this respect Brown (2004) defined a taxonomy of imperfect knowledge as illustrated in Fig. E 2.

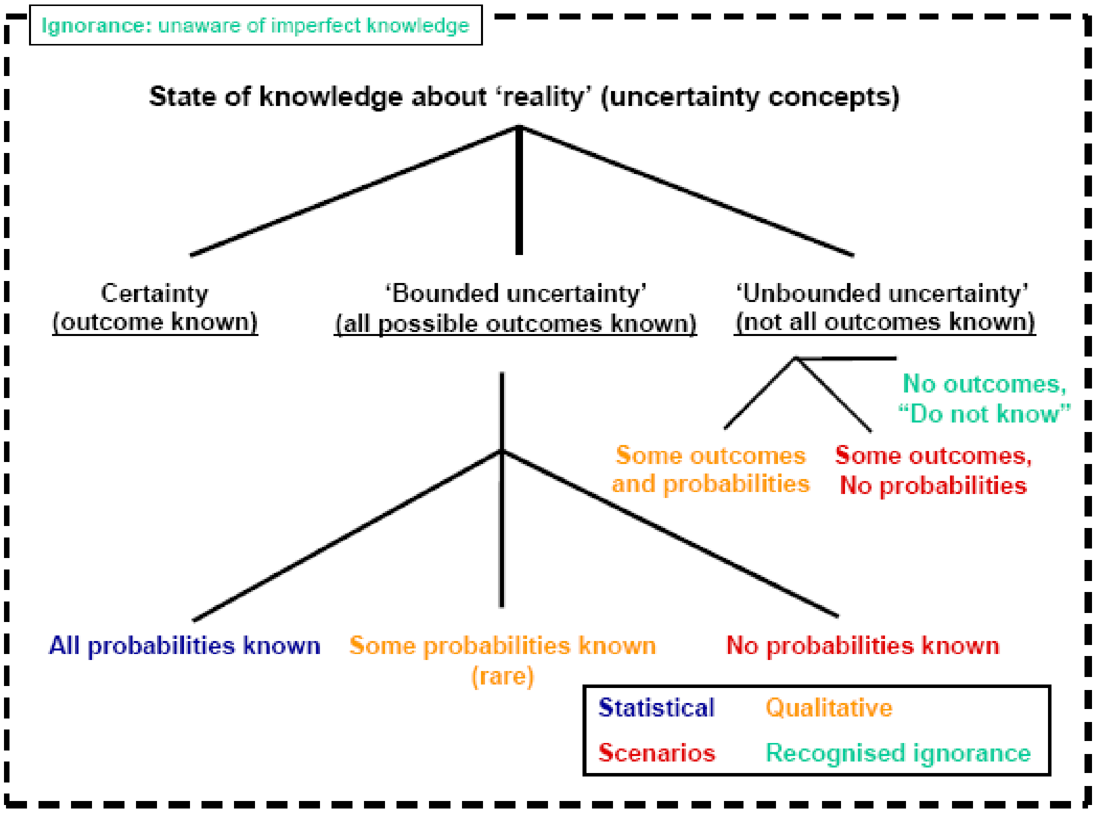

Fig. E 2 *Taxonomy of imperfect knowledge resulting in different uncertainty situations (Brown 2004)*

If probabilities cannot be quantified in any undisputed way, such as may be the case for certain geological properties of the reservoir rock, we often can still qualify the available body of evidence for the possibility of various outcomes. Inspired by legal practices, Weiss (2003a and 2003b) developed the following twelve-point subjective scale for qualification:

– impossible
– hunch
– reasonable suspicion
– reasonable belief

– reasonable indication
– preponderance of the evidence
– substantial and credible
– clear indication
– clear showing
– clear and convincing
– beyond a reasonable doubt
– beyond any doubt

The uncertainty guidance provided for the Fourth Assessment Report (IPCC 2007) is going a step further, by drawing a careful distinction between levels of collected judgement of confidence in scientific understanding and the likelihoods of specific results. This allows for expression of high confidence that an event is extremely unlikely (e.g., rolling a dice twice and getting a six both times), as well as high confidence that an event is about as likely as not (e.g., a tossed coin coming up heads). Confidence and likelihood as used here are distinct concepts but are often linked in practice. Table E 1 gives the standard terms to define levels of confidence as given in the IPCC Uncertainty Guidance Note.

Table E 1 *Confidence terminology (IPCC 2007)*

Confidence Terminology	Degree of confidence in being correct
Very high confidence	At least 9 out of 10 chance
High confidence	About 8 out of 10 chance
Medium confidence	About 5 out of 10 chance
Low confidence	About 2 out of 10 chance
Very low confidence	Less than 1 out of 10 chance

Table E 2 gives the standard terms used in the Fourth Assessment Report (IPCC 2007) to define the likelihood of an outcome or result where this can be estimated probabilistically (value- or statistical uncertainty).

Table E 2 *Likelihood terminology (IPCC 2007)*

Likelihood Terminology	Likelihood of the occurrence/ outcome
Virtually certain	> 99% probability
Extremely likely	> 95% probability
Very likely	> 90% probability
Likely	> 66% probability
More likely than not	> 50% probability
About as likely as not	33 to 66% probability
Unlikely	< 33% probability
Very unlikely	< 10% probability
Extremely unlikely	< 5% probability
Exceptionally unlikely	< 1% probability

It is recommended to use the same standard terminology as used in the IPCC Fourth Assessment report (IPCC 2007) for describing the confidence in scientific understanding and likelihoods (probabilities) for leakage of CO_2 from underground reservoirs.

E.1.2. Sources of uncertainty

Uncertainty can be described as manifesting itself at different locations in the model based process of evaluating CO_2 flow in underground reservoirs. These locations, or sources, may be characterized as follows:

- Context, i.e. at the boundaries of the system to be modelled. The model context is typically determined at the initial stage of the study where the problem is identified and the focus of the model study selected as a confined part of the overall problem of CO_2 leakage potential from underground reservoirs. This includes for example the external economic, environmental, political, social and technological circumstances that form the context of the problem of CO_2 storage.
- Input uncertainty in terms of external driving forces and system data that drive the model such as geological maps, drilling descriptions, pressure measurements and seismic data.
- Model structure uncertainty is the conceptual uncertainty due to incomplete understanding and simplified descriptions of leakage paths, flow and chemical processes as compared to nature.
- Parameter uncertainty, i.e. the uncertainties related to parameter values, such as permeability, porosity, fracture aperture and connectivity.
- Model technical uncertainty is the uncertainty arising from computer implementation of the model, e.g. due to numerical approximations and bugs in the software.
- Model output uncertainty, i.e. the total uncertainty on the model simulations taken all the above sources into account, e.g. by uncertainty propagation.

E.1.3. Nature of uncertainty

The nature of uncertainty can be categorized into:

- Epistemic uncertainty, i.e. the uncertainty due to imperfect knowledge.
- Stochastic uncertainty, i.e. uncertainty due to inherent variability.

Epistemic uncertainty is reducible by more study, comprising research and data collection. Stochastic uncertainty is non-reducible.

The uncertainty on the event of leakage of CO_2 from an underground reservoir includes both epistemic and stochastic uncertainty. The (epistemic) uncertainty of leakage may be reduced by improving the data analysis, carrying out more surveys (seismic, pressure, core-drilling) or by deepening the understanding of how the modelled system of leakage paths works. No matter the amount of data and understanding of the system, there will be some stochastic uncertainty inherent to the natural system, related to the stochastic and chaotic nature of natural phenomena, such as reservoir rock genesis and post-depositional processes determining porosity, permeability and heterogeneity. Perfect knowledge on these phenomena cannot give us a deterministic prediction, but would have the form of a perfect characterization of the natural variability; for example, a probability density function for permeability of the caprock.

E.2. Methodologies For Uncertainty Assessment

Transparency and reporting are essential for a good uncertainty assessment. Many methodologies and tools suitable for supporting uncertainty assessment have been developed and reported in scientific literature. No methodology is applicable to address all the different aspects of uncertainty assessment. The following general description of statistical rock physics methods and workflow is based on Avseth et al. (2005).

Probabilities, random variables and probability distributions are the basic building blocks of uncertainty. Uncertainty is modelled mathematically by random variables. Random variables are uncertain numbers. They can be continuous (e.g. uncertain porosity) or categorical (uncertain shale/sand lithology). Statistical probability density functions (pdfs) and cumulative distribution functions (cdfs) are one way to describe quantitatively the state of our knowledge – or lack of knowledge – about the random variable. Categorical random variables are described by their probability mass function (pmf). If a random variable *X* has a pdf *f(x)*, then specifying *f(x)* allows us to compute probabilities associated with *X*:

$$P(a < X < b) = \int_a^b f(x)dx$$

The cdf is obtained by integrating the pdf. This distribution functions are the shapes that describe the uncertainty quantity. To estimate the unknown pdf from observed data, several methods are available:

- Parametric approach by assuming that the pdf is a known function (e.g. Gaussian) and estimate the paramaters (e.g. mean and variance) of the function from the data.
- Non-parametric approach by making less rigid assumptions about the functional form of the pdf , but let the data speak. The simplest form is the histogram, possibly improved upon by kernel estimators (Silverman 1986).

Pdfs and random variables help to quantify the distributions and variability of target CO_2 storage reservoir properties. Estimates of the variability are data-dependent and model-dependent, and subject to prior knowledge. All estimates of uncertainty are subjective.

Avseth et al. (2005) describe the following 4-step statistical rock physics workflow with regard to exploration geophysics (Fig. E 3). In general, it is applicable for assessment and verification of CO_2 leakage potential in geologic reservoirs as well:

1. *Well-log analysis and facies definition.*
   Well-log data are analyzed to obtain facies definition. The term "facies" is used for categorical groups, not necessarily only by lithology type, but also by some property or a collection of properties, for example a combination of lithology and pore fluids or a lithology and its fracture characteristics. Basic rock physics relations such as velocity-porosity and V_P-V_S are defined for each facies. A critical point is that each facies is not a single rock, but a collection of geologically similar rocks that span a range of petro-physical and seismic properties. The intrinsic variability of rock presents one of the biggest challenges of quantitative seismic interpretation: when does an observed attribute change indicate a significant change across facies rather than a minor fluctuation within a facies? With regard to CO_2 leakage potential, it is the spatial variability of the caprock that probably poses the biggest interpretation challenge.
2. *Rock physics modelling, Monte Carlo simulation and pdf estimation.*
   Monte Carlo simulation (Newendorp and Schuyler 2000, Harbaugh et al. 1995) of seismic rock properties is performed and the facies-dependent statistical pdfs for seismic attributes are computed. Pdfs must be estimated from prior knowledge or available data. A key-feature is the use of rock physics modelling to extend the pdfs to situations not encountered in wells (e.g. different fluid saturations, presence of fractures, different levels

of diagenesis or cementation). The extended pdfs are the derived distributions. Derived distributions allow a more powerful strategy for assessing storage reservoir potential than would be possible by using either purely deterministic models or purely statistical models. Using the derived pdfs of seismic attributes, feasibility evaluations are made about which set of seismic attributes contains most information of the problem. Discriminating thief zones caused by different lithologies may require a different set of attributes than discriminating fractured zones from non-fractured zones.

3. *Seismic inversion, calibration to well pdfs, and statistical classification.*
   The seismic attributes (reflectivities, velocities, impedances) from seismic inversion or analyses (AVO, impedance inversion, etc.) are used in a statistical classification technique to classify the voxels within the seismic attribute cube. The classes could represent different facies, fluid types, fractured vs. unfractured rock, etc. Calibration of the attributes with the probability distributions defined at well locations obtains a measure of probability of occurrence for each facies. Various standard statistical validation tests (e.g. discriminant analysis, K-nearest neighbour classification, neural networks, classification trees, Bayesian classification) are available to obtain a measure of the classification success. Avseth et al. (2005) refer to Duda et al. (2001) and Hastie et al. (2001) for general texts covering many algorithms.
4. *Geostatistical simulations incorporating spatial correlation and fine-scale heterogeneity.*
   Geostatistics is used to include the spatial correlation, represented by variograms or multiple-point spatial statistics, and the small-scale variability, which is not captured by seismic data due to their limited resolution. This final geostatistical step may be used to update the seismically derived probabilities by taking into account geologically reasonable spatial correlation and by conditioning to the facies and fluids observed at well locations.

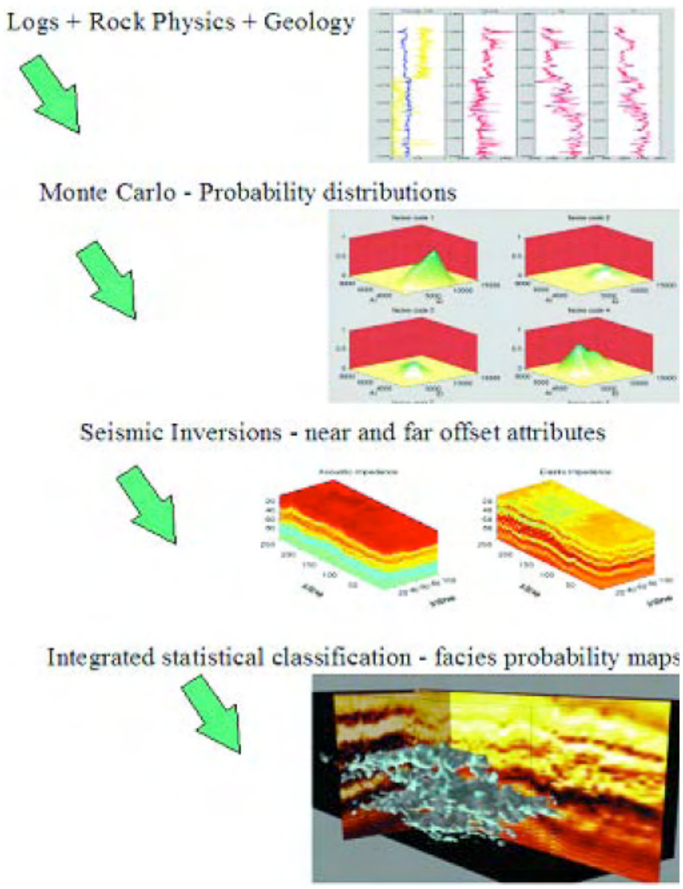

Fig. E 3 *Statistical rock physics workflow (Avseth et al., 2005)*

Dependent on the potential storage site, not all of the steps may be carried out in the initial stages of CO_2 storage assessment. At new sites, with no exploration history and with no well data available, the pdfs of aquifer and cap rock properties may be on the basis of analogous data from regions of similar geologic history. At former exploration sites, the described workflow has been recorded and new information has been gathered during the exploration stage. On the basis of often vast amounts of well- and production data, facies and categories are available and may possibly be refined for both the storage reservoir and the cap rock. Additional seismic attributes extracted after temporal seismic investigations (4D seismic) and careful inversions over a full 3D volume can be used in evaluation of the leakage potential. In this case, the lithologies stay constant and the changes in seismic signatures observed are due to production related changes in fluid saturation and pressure.

Multi-phase flow simulation can be used to constrain the saturation and pressure related changes in seismic attributes. New trends are discussed for studies of fractured reservoirs. The close integration of fracture prediction and multi-phase flow simulation enables significant reductions in (statistical) uncertainty by using all the available static and flow data to constrain a single model (Bourne et al. 2000).

The long term-storage of CO_2 must be verified to ensure the success of geologic carbon sequestration projects. Therefore, care has to be given to verification of the statistically estimated leakage by monitoring. Adequate monitoring is essential in order to derive the actual distributions of the migrating CO_2, not only for different fluid saturations and pressure variations, but also for different spatial scales of heterogeneous saturations. Lewicki et al. (2005) present a strategy that integrates near-surface measurements of CO_2 fluxes or concentrations with an algorithm that enhances temporally- and spatially-correlated leakage signals while suppressing the background noise. The strategy uses synthetic CO_2 flux data sets and modelled surface CO_2 leakage. It provides a means of estimating the number of measurements required to detect a potential CO_2 leakage signal of given magnitude and area. If leakage is detected, further geophysical, geochemical and reservoir management techniques can be applied to locate and mitigate the leak.

E.2.1. New approaches in predictive modelling of naturally fractured aquifers

To understand the CO_2 leakage potential from underground reservoirs, the field-scale distribution of fracture properties in the reservoir and caprock must be understood and quantified. Bourbiaux et al. (2005) give a review of the challenges and some recent solutions to improve modelling of naturally fractured reservoirs.

Quantifying the uncertainty on the fracture information inferred from seismic anisotropy analysis as described is a challenge for extended use of seismic data in fracture characterization studies. Bourbiaux et al. (2005) describe a trend towards and integrated workflow to model naturally fractured reservoirs, starting with the geological analysis of fractures and ending with the reservoir multiphase simulation. A significant progress is expected in the coming years from:

– Additional fault/fracture modelling constraints derived from geomechanical concept and from 3D/4D seismic surveys designed for fracture characterization.
– Improved reliability of field-scale flow simulators through the proper integration of multi-scale flow heterogeneities by means of mixed models coupling discrete and homogenized representations of geological fault/fracture objects.

– Capability to drive the geological modelling of faults and fractures by efficient flow history matching procedures.

These developments are expected to increase the understanding and locating of potential CO_2 leakage paths and the statistical uncertainty involved.

The trend in field studies of fractured rocks is toward the use of methodologies and software platforms to integrate all deterministic and statistical information about fractures into flow simulation models. Borbiaux et al. (2005) describe a workflow involving the following steps:
– Constrained modelling of the probable geological fracture network based on the analysis, interpolation and extrapolation of fracture information acquired in wells and derived from seismic data, sometimes completed with outcrop analogue data.
– Characterizing the hydrodynamic properties of this modelled natural network from flow-related data.
– Choosing a flow simulation model suited to the role played by fractures and faults at various scales and assigning to this model upscaled parameters derived from the flow-calibrated geological fracture model.
– Simulating the reservoir flow behaviour on the basis of a physical assessment of multiphase flow mechanisms acting in transfers between matrix and fractures.

The above workflow can be applied to CO_2 storage assessment and verification projects. Quantifying the uncertainties involved in several steps of this workflow however, is a key challenge.

Although geologists can provide detailed classification of fractures with various sets associated with tectonic events and tensile or shear mechanisms, the reservoir engineer assessing the flow mechanisms within the fractured aquifer, is led to discard and/or lump sets expected to have negligible or similar impact on flows in order to be able to create a flow model. In practice, we generally end up with two main categories, the large-scale fractures or faults at seismic and sub-seismic scale and the small-scale or diffuse fractures observed in wellbores. Based on this a multi-scale fracture model is built using stochastic methods (Bourne et al. 2000) constrained by the deterministic observations and fracture genesis rules. However, this Discrete Fracture Network (DFN) model will not be used as it is, but will be simplified through homogenisation procedures. DFN models are used to assess fracture hydraulic properties form available field flow data. Interpreting flow data using geologically representative DFN models provide additional information about reservoir and leakage flow properties compared to conventional analysis methods. It is important that these DFN models keep the link with the geological assumptions underlying the fracture model (Bourbiaux et al. 2005).

Bourne et al. (2000) present a new semi-deterministic method to systematically predict the spatial distribution of natural fractures and their effect on flow simulations in order to optimize recovery of oil and gas from naturally fractured reservoirs. This method may be applicable to assessment of potential CO_2 leakage from underground reservoirs and is summarized here. In short, rocks obey physics, and physics can be used to predict fractures that affect flow across entire naturally fractured reservoirs.

Traditionally, methods of fracture modelling in oil and gas production are geostatistical. They rely on stochastic realizations of the large number of fracture networks consistent with borehole fracture data. This approach is limited to near-well scales as it lacks information on how fracture statistics may change away from the wells. A field-scale stochastic fracture model requires an enormous number of evenly distributed wells to allow simple interpolation of fracture statistics between the wells.

The new method described by Bourne et al. (2000) for predicting natural fracture distributions and their effect on reservoir simulations uses geomechanics and flow simulation. It considers geomechanical methods to predict field-scale distribution of fracture networks that affect flow with reservoir simulations. Thereafter, multi-phase flow simulations of the fracture model are validated and calibrated against well test and production data. The close integration of fracture prediction and flow simulation enables significant reductions in (statistical) uncertainty by using all the available static and flow data to constrain a single model. As the model parameters are field-scale (i.e. mean rock strength, remote stress, etc.), information from each well constrains the whole fracture model and not just the areas around the (production or injection) wells. This makes the model suitable for fracture prediction and flow forecasting in all parts of the reservoir and not just the parts around existing wells.