Chapter 9
Natural Analogue Studies

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Abstract Lessons learned from sites where CO_2 has naturally been stored for long geologic periods of time provides valuable information for assessing proposed anthropogenic storage sites. This chapter discusses the natural CO_2 storage analogue sites and looks at them worldwide to determine which geological characteristics are preferable for natural CO_2 storage and which are not. Following this, an approach is presented based on geomechanical facies, for a comparative assessment of storage sites, accounting for features observed in the natural analogue sites. Finally, a number of anthropogenic storage sites are classified according to the characterization criteria and a detailed description of a number of natural and anthropogenic storage sites are presented.

9.1 Introduction

In this chapter we define what a natural CO_2 storage analogue is, then we look at an extensive catalogue of analogue storage sites worldwide to determine which geological characteristics are preferable for natural CO_2 storage and which are less preferable. We then apply a holistic approach using geomechanical facies to enable a comparative assessment of storage sites accounting for the various features seen in the natural analogue sites, relating to the individual tectonic and depositional settings. Following this, anthropogenic storage sites are classified according to the

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characterization developed from using a geomechanical facies framework, providing a good match indicating that the geomechanical facies approach provides a good first order method of assessment for storage sites. We then provide a detailed conceptual model description and hydro-mechanical parameterization of several natural and anthropogenic storage sites based on the geomechanical facies analysis (Otway, Australia—CO_2 storage project, In Salah, Algeria—CO_2 storage project, Sleipner, Norway—CO_2 storage project, Snøhvit, Norway—CO_2 storage project, Buracica, Brazil—CO_2 Enhanced Oil Recovery, Miller Field, UK North Sea—natural CO_2 reservoir, St. Johns Dome, USA—natural CO_2 reservoir, Fizzy Field, UK Southern North Sea—natural CO_2 reservoir). Finally, in conclusion, we address what we learned from the analogue studies and the application of geomechanical facies approach.

Where CO_2 has been naturally stored over long periods of time in rocks, we can learn lessons from the natural geological conditions regarding what factors are important to retain the CO_2 compared to other rocks where CO_2 is present but not retained. These sites are natural analogues to the proposed engineered storage sites for CO_2. Natural analogue sites provide the possibility to investigate and determine the key factors which ensure the storage of CO_2 and allow scientists to develop selection criteria based on these factors when identifying contemporary engineered storage sites.

CO_2 originating from natural sources such as mantle degassing, volcanism, carbonate rock metamorphism and the degradation of organic matter, is common in sedimentary basins world-wide (Wycherley et al. 1999). Sedimentary basins are formed by layers of strata. A stratum is a layer of sedimentary rock with internally consistent characteristics distinguishing it from other layers. Strata comprise multiple stratum. Typically different types of strata can be found in sedimentary basins, from highly permeable porous rocks such as sandstones, which form good reservoir rocks, to rocks with a very low permeability such as shales, mudstones or evaporites, which can act as effective barriers and thus as seals. Naturally occurring CO_2 is often found in reservoir rocks in which it can reside as either free phase or dissolved within the fluid found within the pores of the rock. Sealing rocks above the reservoir rock can prevent the vertical movement of CO_2 over geological time-scales.

In cases where CO_2 naturally occurs within a reservoir rock-sealing rock sequence located within a structural or lithologic geologic feature that inhibits lateral or vertical movement of the fluids within the reservoir rock, a so-called trap, the site can be identified as a natural analogue for engineered geological CO_2 storage sites. This is because the site has all the features of proposed engineered storage sites such as a reservoir rock—sealing rock pair, a trapping mechanism, and CO_2.

Natural analogues for CO_2 stores can offer unique insights into the long-term behavior and retention of CO_2 in the subsurface (Baines and Worden 2004) and thereby provide truly long-term data on the interaction of CO_2 with the reservoir and caprocks, which are impossible to reproduce in laboratory studies or short-term field experiments. In addition, such sites offer geological evidence of ancient and/or current migration of CO_2 out of the primary reservoir, sometimes all the way to the surface. These can offer insights into the mechanisms by which engineered sites may fail and which properties are optimal for a secure storage site and thus give information relevant for the selection of effective CO_2 storage sites.

Analogue CO_2 storage sites provide experimental evidence of storage performance over long geological time scales, and provide important insights into the key controls of the storage system. The main factors important in enabling CO_2 storage can be shown to be the same for most storage sites. Therefore there are certain common factors which can be compared and contrasted world-wide. Specifically, recognizing that storage sites have holistic characteristics—that is, there is a reservoir rock, a seal rock and an overburden—and by investigating the primary controls on the formation of these systems, including deposition, diagenesis and stress controls, it is possible to identify which sites are likely to provide better storage locations than others.

In order to identify factors that render a site a secure storage site—the opposite of an insecure storage site from which CO_2 is leaking to the surface—over 60 naturally occurring CO_2 reservoirs where CO_2 has been stored over geological time-scales, and in some cases is migrating to the surface, were investigated. This global dataset was then examined for consistent mechanisms leading to the secure retention of CO_2 in the subsurface reservoirs and to identify which processes may lead to the migration of CO_2 out of the reservoir to the surface.

In a second step we compared different sites, including natural analogues and existing CO_2 storage sites, using the framework offered by considering the geomechanical facies present. A geomechanical facies is a conceptual building block for the subsurface. It has specific material characteristics defined by the geology of the rocks and defined by the engineering use to which it will be put. A good analogy is the use of different bricks with the construction of a house. Each brick has certain characteristics, and is used for a certain purpose. The combination of the bricks forms the house, its shape and its individual appearance. We try and identify the characteristics of the "geological" bricks, the geomechanical facies, and then use this concept to compare different sites.

A geological facies is defined as a body of rock with specified characteristics (Reading 1978). A geomechanical facies is described as a series of geological facies grouped together on the basis of engineering parameters that fulfil a specific role within the storage system, e.g. reservoir, caprock, overburden (McDermott et al. 2006). For complete CO_2 storage site assessment, in addition to the basin architecture and sedimentary stratigraphy, the fluid flow characteristics (hydrogeology) and the mechanical characteristics (fractures, rock strength and elastic properties) are particularly important.

Using a geomechanical facies framework, the factors crucial to assessing the CO_2 storage security of a storage basin such as basin architecture, caprock architecture, reservoir quality, stress state, mechanical characteristics, fractures, burial depth, geothermal gradient, risk of orogenic modification, structural stability and preservation potential, can all be taken into account.

Obviously the tectonic setting exerts a principal influence over these components. Different tectonic settings exhibit different depositional process controls.

This directly influences sediment thickness and the distribution of the caprock and reservoir sediments (Hallam 1981). The tectonic setting also determines basin architecture, stress state, mechanical characteristics, fracture properties, burial depths, geothermal gradient, structural stability and preservation potential. An additional factor of importance is the facies distribution within the caprock, and their heterogeneity.

By examining the typical characteristics of the geomechanical facies within the different tectonic settings, it is possible to compare and contrast the different tectonic settings to appraise global CO_2 storage opportunities and predict which tectonic settings will be most suitable for CO_2 storage.

9.2 Natural Analogue Sites and Key Storage Controls

One of the key challenges when studying naturally occurring CO_2 reservoirs as analogues for storage sites, is to correctly determine whether a site is secure, storing CO_2 without any leakage for geological time scales, or insecure, with leakage of CO_2 to the surface occurring. It is crucial that sites are correctly identified if mechanisms that lead to leakage and thus insecure storage site are to be analyzed. Movement of natural CO_2 to the surface can be identified by various surface manifestations often called CO_2 seeps (Roberts et al. 2011). These include

- dry CO_2 degassing via focused vents (a discrete opening that allows gas to pass out of the soil) or diffusely over an area without a discrete vent;
- CO_2-driven mud volcanoes or mofettes (a mofette is a vent from which carbon dioxide and some nitrogen and oxygen issue from the earth in a last stage of volcanic activity); and
- springs with CO_2-rich groundwaters that in some cases are accompanied by travertine deposition (a carbonate rock that precipitates when CO_2-rich waters degas on reaching the surface).

It has to be noted that CO_2 seeps are not necessarily related to a subsurface CO_2 reservoir but may instead represent an open system where CO_2 flow is not constricted and thus CO_2 does not accumulate in large quantities in the subsurface (Roberts et al. 2015). This is important as it shows that not every CO_2 seep on the surface is related to a CO_2 bearing reservoir rock in the subsurface from which CO_2 is migrating. Indeed, many known occurrences of CO_2 seeps are related to volcanic activity and are not linked to an analogue site (reservoir rock—sealing rock pair, a geological trap) in depth.

Natural CO_2 reservoirs at a regional scale have been examined as analogues for saline aquifer carbon storage sites for different regions: the Colorado Plateau (Stevens et al. 2001), Europe (Holloway et al. 2005; Pearce et al. 1996, 2004) and China (Dai et al. 2005), but not on a global scale yet. According to these studies, migration from subsurface CO_2 reservoirs towards the surface occurs mainly along

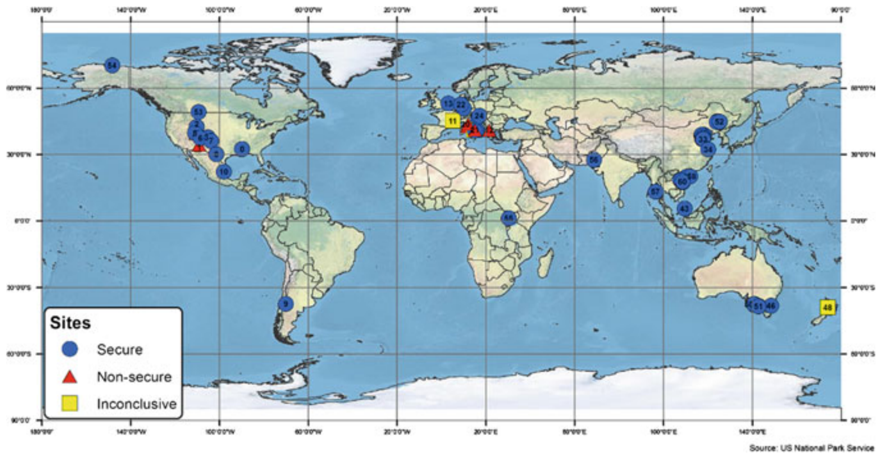

Fig. 9.1 Map showing the locations of natural CO_2 reservoirs included in this study. *Map source* US National Park Service

small and large discontinuities (fractures and faults) within the rocks that are between the reservoir in depth and the surface. Faults (and fractures) can be generally described as planar features and therefore migration of CO_2 along faults is spatially restricted. The fact that faults and fractures are the main migration pathways is not very surprising as fault zones have long been recognized as fluid migration pathways in the subsurface for oil, gas, and groundwater (Faulkner et al. 2010). Considerable research has been completed in the last decades on the hydraulic properties of faults, in particular on the predictability of whether hydrocarbons will or will not flow up or through fault zones (Manzocchi et al. 2010).

We have examined 61 naturally occurring CO_2 reservoirs around the globe in order to better understand the mechanisms that lead to migration of CO_2 out of subsurface reservoirs to the surface and what controls the secure retention of CO_2 within such reservoirs (Miocic et al. 2013; Miocic et al. 2016). The locations of the studied reservoirs are shown in Fig. 9.1. For a reservoir to be classified as insecure, evidence of CO_2 migration to the surface had to be present. This includes all of the above listed types of CO_2 seeps. If such a seep was located within a 10 km surface radius of the subsurface extent of the natural CO_2 reservoir, the reservoir was classified as insecure. The 10 km radius is based on an extensive study of natural CO_2 seeps in Italy by (Roberts 2012) which conclusively found that surface seeps linked to deep naturally occurring CO_2 reservoirs which held CO_2 in a free phase—rather than holding CO_2 dissolved in the pore-fluid—occurred within a 10 km radius of boreholes which encountered the free phase CO_2 in depth.

Of the 61 studied naturally occurring CO_2 reservoirs, six (10 %) show clear evidence of CO_2 migration to the surface and have therefore been classified as insecure. Three (5 %) reservoirs show inconclusive evidence for a successful retention of CO_2 in the subsurface: Montmiral in SE France, which is used as a secure example by Pearce et al. (2004), has many CO_2 rich springs within a 10 km radius of the field which provide evidence for CO_2 migration to the surface. However, it is currently unclear if the CO_2 originates from the reservoir or is sourced from elsewhere. The Monte Taburno reservoir in central Italy is located just 1.6 km from a thermal spring with a small CO_2 content and since there is no further geochemical information about the spring or the CO_2 reservoir, the relationship between the two is unclear (Roberts 2012). The Paritutu reservoir offshore New Plymouth, NZ, is shallow and there is a vent at the surface degassing CO_2 (Lyon et al. 1996). However, the distance between the reservoir penetrating well and the vent is unknown, as are the possible CO_2 migration pathways. Fifty-two reservoirs (85 %) show no evidence of CO_2 migration to the surface above or within a 10 km radius of the subsurface extent of the reservoir, which was concluded to provide sufficient evidence that these reservoirs are successfully sealed. Features of the natural analogues are compared and contrasted below to identify the factors that promote the security of the storage and those which can be associated with leaks.

9.2.1 Properties of Naturally Occurring CO_2 Reservoirs

The CO_2 contained in the studied reservoirs is mainly sourced from mantle degassing and igneous processes. This was the case for 62 % of the 35 reservoirs for which stable carbon isotope and noble gas geochemical data is available, with the remainder being sourced from the thermal breakdown of marine carbonates and organic matter. The CO_2 concentrations (vol.% of gas produced) in the reservoirs

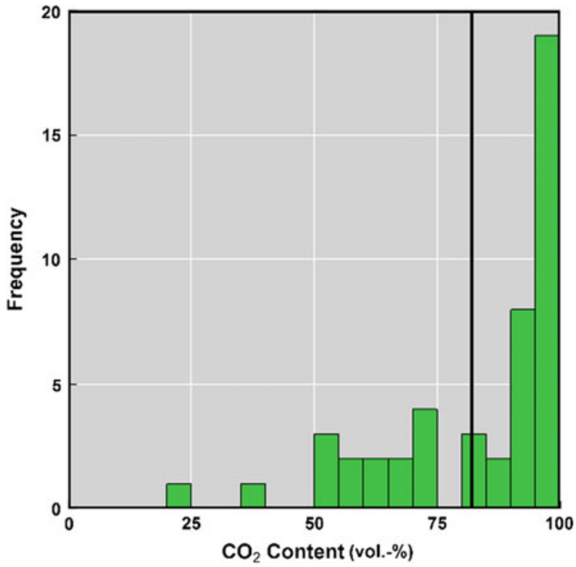

Fig. 9.2 Frequency plot showing the CO_2 concentration in the studied natural reservoirs. The average concentration is 82 %, with the majority of reservoirs holding CO_2 in concentrations of more than 90 %

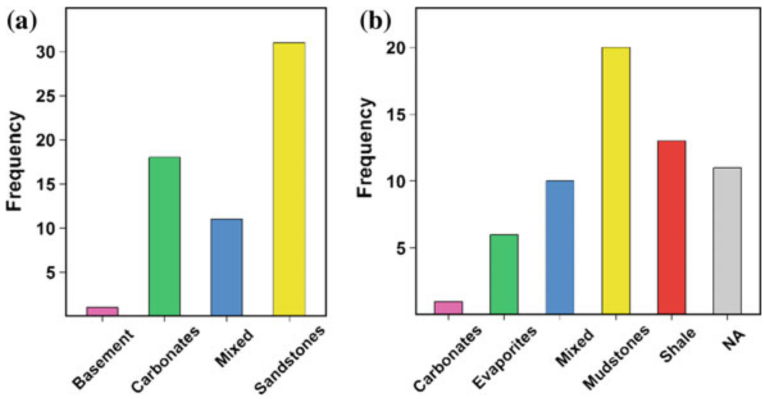

Fig. 9.3 Frequency plots showing **a** the distribution of reservoir rocks and **b** the distribution of sealing rock lithologies of the studied naturally occurring reservoirs

range from 20 to >99 %, with an average concentration of 82 % (Fig. 9.2). This shows that the studied natural reservoirs are good analogues for saline aquifer storage sites where the CO_2 content is to be thought more than 80 %. The natural reservoirs with lower concentrations are analogues for storage sites in depleted oil and gas fields where the CO_2 concentration is naturally lower as residual oil and gas also fills the pores. Other frequently trapped gases include, in order of decreasing abundance; methane, nitrogen, helium and H_2S. It should be noted that there were no notable differences in the CO_2 composition, origin or concentration between the secure and non-secure reservoirs.

The reservoir rocks of naturally occurring CO_2 reservoirs are commonly siliciclastic lithologies (50 %) with sandstones dominating and only minor amounts of siltstones and conglomerates (Fig. 9.3). The other principal reservoir rock lithologies are carbonates (30 %), with limestones and dolomites being equally represented. In some of the analogue sites interlayered carbonate and siliciclastic rocks (17 %) form the reservoir sequence and in one single case basement rocks form the reservoir. While the data on the composition of reservoir rocks is available for all studied naturally occurring CO_2 reservoirs, data on caprock (or sealing rock) is less frequently accessible. This is related to the fact that many of the CO_2 reservoirs are found during exploratory drilling for hydrocarbons. When the operators realize that no hydrocarbons occur within the reservoir they often abandon the well without conducting a detailed analysis of the reservoir-seal interval. For the studied CO_2 reservoirs for which data on the caprock is available, the dominant lithologies are fine grained silicate mudstones and shales (54 %). Interlayered carbonate and mudstone/shales are also common (16 %, Fig. 9.3). Other caprock lithologies are evaporites, with anhydrite and halite both acting as primary seals. There is no relationship between the type of reservoir rock or caprock and the capability of a reservoir to successfully retain CO_2 for geological periods of time. This indicates that both siliciclastic and carbonate rocks can form good reservoir rocks for carbon

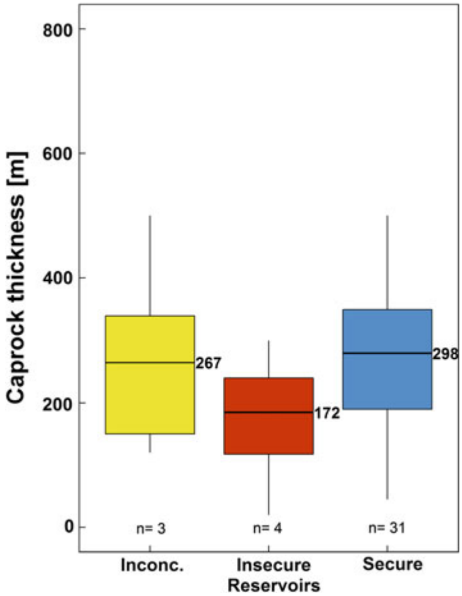

Fig. 9.4 Boxplot of caprock thickness as determined from available geological data against secure and insecure CO_2 reservoirs. The caprock above sealing reservoirs is generally thicker than caprock above insecure reservoirs. The *boxplot* shows the median (*black horizontal line*) and the interquartile range. The *whiskers* (*black vertical line*) depict the 1.5 inter-quartile range

storage sites, and that any caprock, if thick enough (see below), can successfully prevent CO_2 from migrating out of the reservoir.

The thickness of the low permeability and porosity lithology directly above the reservoir seems to have a direct influence on whether a naturally occurring CO_2 reservoir is secure or insecure: Caprocks of secure reservoirs are about twice as thick as caprocks of insecure reservoirs, which have an average thickness of 172 m (Fig. 9.4). Caprocks of the inconclusively secure reservoirs are also on average thicker than the caprocks of insecure reservoirs. Note that here the limitations of the dataset are of importance: There are only three data points for inconclusively secure reservoirs and only four data points for insecure reservoirs while there is data for 31 secure naturally occurring CO_2 reservoirs. Thus there are some uncertainties with this statistical examination and more insecure reservoirs should be added to the dataset in the future. Sites where the caprock directly above the reservoir is not the only low-permeability rock in the rock column above the reservoir but only one of several caprocks, appear to assist the successful retention of CO_2 in the subsurface. Such multi caprock systems or layered compartments occur in at least 30 % of the secure reservoirs, with up to five different reservoir horizons, each corresponding with a caprock. Only one of the insecure reservoirs has layered compartments and these seem to be connected via fracture networks.

For CO_2 storage sites the pressure and temperature within the reservoir rock are important as they govern CO_2 properties such as density and physical state which in turn determine the amount of CO_2 that can be stored within the reservoir. Fluids within sedimentary rocks are under pressure, and this pressure generally increases with depth, the deeper a rock is the higher the pressure of the fluid within the pores is.

There are three pressure gradients within the subsurface which play an important role: (1) in an open system where fluids can move both vertically and laterally through the subsurface and thus dissipate pressure, pore fluids have pressures along the hydrostatic gradient which is at around 10 kPa/m. If movement of fluids is restricted, pore pressures are commonly higher than the hydrostatic gradient (overpressured). (2) If the pore pressure continues to increase, it will overcome the strength of the rock and induce fractures. The pressure at which this occurs is called fracture gradient and is related to (3) the lithostatic gradient. The lithostatic gradient is the pressure caused by the overlying rock material and is a function of depth, rock density. Temperatures in the subsurface generally increase with depth, with deeper rocks having higher temperatures. The gradient that defines the temperature increase differs from sedimentary basin to sedimentary basin, with basins located in areas with a thin lithosphere or strong magmatic activity having a high temperature gradient while basins on cratons having a low temperature gradient. The average global temperature gradient for sedimentary basins is in the order of 30 °C/km.

The studied naturally occurring CO_2 reservoirs around the globe are located in a range of depths below the ground surface (Fig. 9.5). The shallowest reservoir is located in only 300 m depth (Messokampos, Greece), while the deepest reservoir is located at a depth of 4600 m (Jackson Dome, USA). Note that insecure reservoirs are, with one exception, located at depths shallower than 1200 m below surface. Due to the wide range of depths it is not surprising that the reservoir fluid pressures also show a wide range, from 0.5 MPa to more than 60 MPa (Fig. 9.5). Shallow CO_2 reservoirs (<1200 m depth below surface) that are sealing are hydrostatically pressured, whereas insecure reservoirs at these depths exhibit pressures both above and below hydrostatic. Some sealing reservoirs that are deeper than 1200 m below surface show excess pressures 40–50 % above hydrostatic. All insecure and inconclusively insecure reservoirs at these depths exhibit high overpressures. These pressures are close to 85 % of lithostatic pressure, the known fracture pressure of caprocks in the North Sea (Moss et al. 2003), and in other sedimentary basins where the rock fractures (Hillis 2003). The reservoir temperatures of the studied naturally occurring CO_2 reservoirs range from 20 to 200 °C, with insecure reservoirs having either “normal” (30 °C/km) or very high temperature gradients (Fig. 9.5).

Based on the temperature and pressure conditions within the naturally occurring CO_2 reservoirs the CO_2 state and density can be calculated (Fig. 9.6). In the studied sites CO_2 occurs as gaseous phase where pressures are less than the critical pressure of 7.39 MPa, and as supercritical phase where pressures are more than 7.39 MPa and temperatures exceed the critical temperature of 31.1 °C. CO_2 densities in the studied sites range from 100 kg/m^3 to more than 800 kg/m^3. Gaseous CO_2 in the studied analogues has densities of <220 kg/m^3, while the density of supercritical CO_2 ranges from 160 kg/m^3 to more than 800 kg/m^3.

Insecure naturally occurring CO_2 reservoirs tend to be shallow and thus have low reservoir pressures. The CO_2 is in gaseous form and in five out of six insecure reservoirs the CO_2 has a density of <200 kg/m^3. A comparison of reservoirs with gaseous and supercritical conditions shows that reservoirs in which CO_2 is stored in a gaseous state are more prone to leakage than reservoirs with supercritical

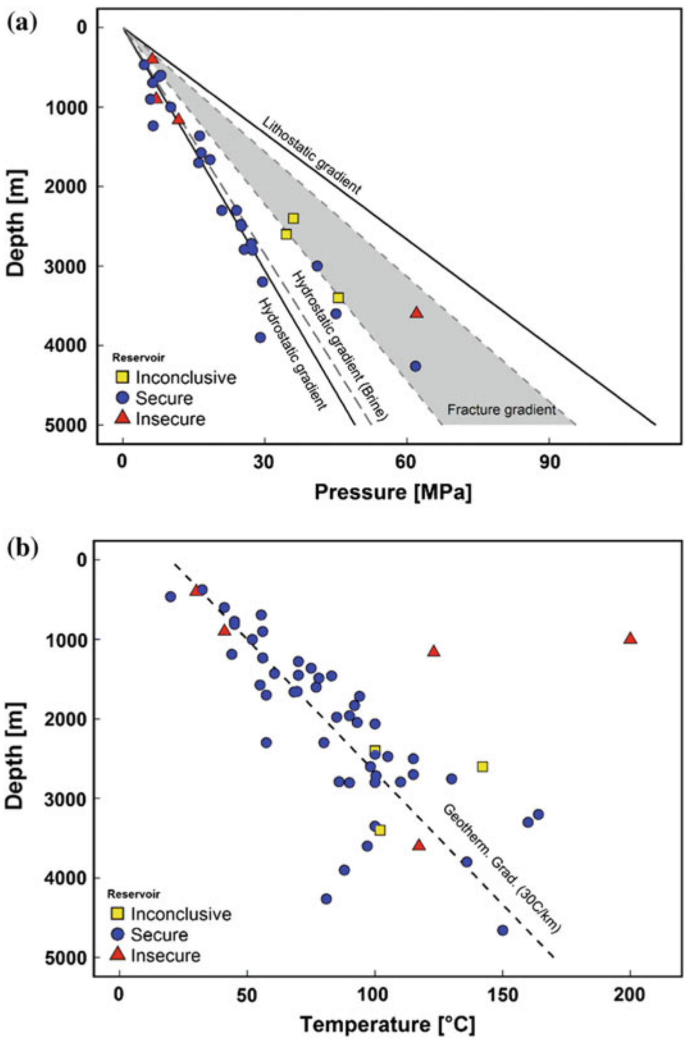

Fig. 9.5 **a** Depth versus pressure plot of natural CO_2 reservoirs with in situ pressure data. Note that non-secure reservoirs are mainly shallow (<1200 m) or within the fracture gradient range. The range of fracture gradients in sedimentary basins is illustrated by the shaded area which ranges from 60 to 90 % of lithostatic stress. The deep, insecure reservoir with reservoir pressure over the fracture gradient is Pieve Santo Stefano, Italy. **b** Depth versus temperature plot of natural CO_2 reservoirs, based on regional temperature gradients as well as in situ data. Note that a high geothermal gradient may lead to migration of CO_2 in shallow reservoirs. Also note that not all reservoirs with temperature data have in situ pressure data and therefore may not be plotted on the pressure graph

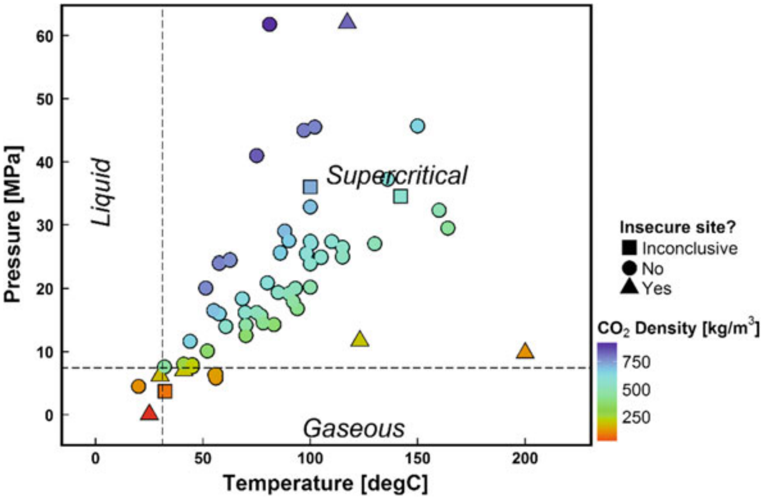

Fig. 9.6 CO_2 state diagram (pressure vs. temperature plot) illustrating the range of reservoir conditions found in naturally occurring CO_2 reservoirs. Reservoirs with gaseous CO_2 and reservoirs with low-density supercritical CO_2 are more likely to be insecure than reservoirs with dense, supercritical CO_2

conditions: 37 % (3 out of 8) of the reservoirs with gaseous CO_2 show evidence for migration of CO_2 out of the reservoir to the surface, while only about 6 % (3 out of 53) of reservoirs with supercritical conditions exhibit such evidence. Here we also relate to recent surprising experimental evidence which suggests that gaseous CO_2 may be more mobile through fractures in the subsurface than supercritical CO_2 (Edlmann et al. 2013).

In some cases CO_2 occurs in several formations of multi-layered reservoirs. Structural geological data indicates that faults are the pathways through which CO_2 migrates from one formation to the next. Faults also play an important role as migration pathways to the surface: for five of the six insecure CO_2 reservoirs, the migrating CO_2 emerges at the surface close to fault tips and traces. Surface manifestations of migrating CO_2 linked to faults are CO_2 rich springs and travertine deposits. While faults are clearly migration pathways that render some of the reservoirs insecure, the mere presence of a fault at a naturally occurring CO_2 reservoir is not equivalent to the reservoir being insecure. More than half (56 %) of the natural reservoirs that securely hold CO_2 over geological timescales are fault bound structural traps. At such traps one (or several) large fault(s) form the boundary of the reservoir and withstand migration of CO_2 through or along the fault. Several more secure reservoirs that are not fault-bound are located in structurally complex and faulted provinces. This is a clear indication that faults often also inhibit CO_2 migration rather than being pathways for leakage. It is noteworthy that the majority of insecure, fault-bound reservoirs are found in tectonically active regions, such as the Apennine thrust belt in Italy or the Florina Basin in Greece.

Therefore active, or close to critically stressed faults, may be more prone to act as migration pathway than faults in tectonically quiet areas. Indeed, the state of stress has a direct influence on the permeability of fault zones (Barton et al. 1995).

9.2.2 *Mechanisms of CO_2 Migration at Naturally Occurring CO_2 Reservoirs*

There are three processes that can lead to the vertical migration of CO_2 from a reservoir through the caprock: Migration through unfractured caprock by capillary flow, migration by fracturing the caprock, and migration through faults (Fig. 9.7). In the following evidence for these processes at the studied naturally occurring CO_2 reservoirs is discussed.

9.2.2.1 Migration of CO_2 Through Unfractured Caprocks

Migration of CO_2 through mudrocks or shales will occur when the pressure in the reservoir exceeds that of the capillary entry pressure of fractures or pores in the seal (Chiquet et al. 2007). The small pore sizes of low permeability rocks require capillary entry pressures of several tens of MPa for this to occur. The density and phase conditions of CO_2 are dependent on pressure and temperature, which is a direct function of the depth of the reservoir. The density contrast between CO_2 and brine in the reservoir decreases with increasing depth, and hence differential buoyancy pressure on the caprock also decreases with increasing depth. For this reason shallow reservoirs (<1000 m depth) are inherently more likely to leak CO_2 through an unfractured caprock. Yet, there are no indications that leakage through the caprock by capillary flow is a leaking mechanism in the studied shallow

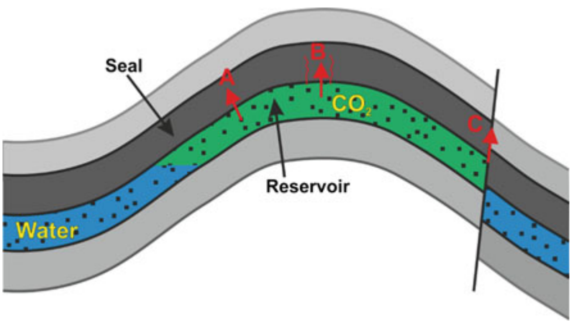

Fig. 9.7 Diagram illustrating three potential migration pathways for CO_2 out of a natural reservoir: (*A*) Migration through unfractured caprock, (*B*) migration by fracturing of the caprock and (*C*) migration along pre-existing faults and fractures. In naturally occurring CO_2 reservoirs only the latter mechanism is found to play a significant role

reservoirs. For leaking CO_2 reservoirs in Italy, Roberts et al. (2015) were able to show that the observed surface CO_2 seep rates greatly exceed the physical possibility of leakage by capillary flow through intact mudrock from the area above the site. Thus CO_2 migration must be via fractures not matrix flow. Lu et al. (2009) showed that even after an estimated 70 Ma, CO_2 only infiltrated 12 m of sealing mudrocks directly over a CO_2 rich oil field in the UK North Sea. Hence, the time-scales required for CO_2 migration through unfractured caprocks are orders of magnitudes longer than those necessary for CO_2 storage to effectively mitigate climate change.

9.2.2.2 Migration by Caprock Fracturing

As burial depth increases, it becomes more likely that fluid pressures will be over pressured, that is, pore pressures deviate from hydrostatic (or "normal") pressures towards lithostatic pressures. If pore pressure in the reservoir exceeds both the pore pressure in the caprock and the tensile strength of the caprock (including any differences in confining stress due to different elastic properties), hydraulic fracturing and/or frictional failure along optimally oriented pre-existing fractures of the caprock occurs (Finkbeiner et al. 2001; McDermott et al. 2013). Both mechanisms can lead to migration of CO_2 from the reservoir through the caprock by fracture flow (Shukla et al. 2010, Fig. 9.7). This effect was induced at the CO_2 injection test site at In Salah (Rinaldi and Rutqvist 2013). Fracturing to form dilatant joints (mode 1 fractures) induced by elevated fluid pressure only occurs when the pressure exceeds the least principal stress of the caprock (Hillis 2003) (this direction of least principal stress is typically horizontal until depths exceed 1.5–2 km (Nara et al. 2011). The pore pressure required to cause such failure is much less than the pore pressure required to overcome the capillary entry pressure of a mudstone caprock (Busch et al. 2010) and so caprocks will transmit CO_2 more readily by fracture flow than by capillary flow. Most sedimentary rocks are fractured during burial and the fracture density depends on the geomechanical properties and thickness of the rock and thus different rock layers fracture differently in response to the same stress (Hanks et al. 1997; Ladeira and Price 1981). Fracture density increases in the vicinity of faults (damage zone) and fractures provide permeability only when open or connected (Faulkner et al. 2003). There is no clear evidence for leakage through dilatant joints in hydraulically fractured caprock in the examined sites.

9.2.2.3 Migration Through Faults

Strong evidence for CO_2 migration through fault induced fractures exists at several insecure reservoirs. CO_2 seeps are frequently located close to active or extinct faults, which may exist prior to CO_2 migration (Roberts et al. 2015; Shipton et al. 2004). Thus fractures and flow through fractures as part of a fault zone play a significant role in permitting CO_2 migration. This indicates that pre-existing faults are important pathways for CO_2 migration, possibly due to increased fracture permeability in the fault damage zone.

9.3 Implications for Engineered CO_2 Storage Sites

Deep (>1500 m) insecure and possibly insecure (inconclusive) reservoirs have high reservoir fluid pressures close to fracture pressure (around 70–85 % of lithostatic pressure) and will therefore readily fail by hydraulic failure (Fig. 9.5). Leak-off data from UK North Sea reservoirs show that the least principal stress in the region is typically within 70–85 % of lithostatic pressure and this has been shown to be the case in other sedimentary basins (Hillis 2003; Moss et al. 2003). Therefore when considering potential sites for engineered CO_2 storage it is critical that the pore pressure, stress history and the present day stress state of the selected storage complex are well understood. It is also imperative that reservoir pressures during CO_2 injection are maintained below the least principal stress of the region. In shallow (<800–1000 m) or hot reservoirs, the low density of gaseous CO_2 compared to the density of reservoir brine leads to a high buoyancy pressure of CO_2 on the caprock. Hence, the differential stress exerted by the state of stored CO_2 needs to be calculated specifically for each individual engineered CO_2 storage sites and especially at potential sites with abnormal temperature gradients. With increasing reservoir pressure (depth) and temperature, CO_2 enters the supercritical state and has a (significantly) higher density, leading to a lower buoyancy pressure. The impact of CO_2 density on migration is highlighted by the fact that two of the three insecure reservoirs where CO_2 is in supercritical conditions have low CO_2 densities (119 and 200 kg/m^3). The larger the difference between the buoyancy pressure and the hydrostatic pressure, the more likely it is that the buoyancy pressure will cause stress change that may cause frictional failure of the fractures. In addition, fault related damage zones and fractures may have an increased permeability when close to critically stressed (Faulkner et al. 2010). Recent experimental investigations of CO_2 flow through naturally fractured caprock indicate that gaseous CO_2 flows more readily through fractures than supercritical CO_2 (Edlmann et al. 2013). From the observations of natural CO_2 reservoirs it can be concluded that migration through faults and fractures is mainly restricted to shallow reservoirs which contain gaseous CO_2 or supercritical CO_2 with a low density.

In recent years studies by international research consortia (including industry, academic and legislative partners) have developed criteria for the selection of industrial storage sites. These criteria, which cover potential risks for CO_2 storage sites from basin-scale (Bachu 2003; Veritas 2010; NETL 2010) to reservoir scale (Chadwick et al. 2008; Delprat-Jannaud et al. 2013; IEAGHG 2009; Smith et al. 2011) are intended to be used to select secure storage sites. Key criteria for all studies include depth, CO_2 state, and the presence of (open) fractures or faults. It is recommended that CO_2 is stored at depths of >800 m (IEA GHG 2009; NETL 2010; Smith et al. 2011) or in depths of >1000 m (Chadwick et al. 2008). Most studies

Table 9.1 Table listing key properties of the six insecure naturally occurring CO_2 reservoirs of this study

Site	Depth (m)	Temperature (°C)	Pressure (MPa)	CO_2 state	Fault
St. Johns Dome	*400–700*	30–49	*6.17*	*Gaseous*	Yes
Farnham Dome	900	41	*7*	*Gaseous*	Yes
Messokampos	*300*	*25*	*0.5*	*Gaseous*	Yes
Latera Caldera	1000	*200*	–	Sc	Yes
Pieve Santo Stefano	3600	117	62	Sc	*Yes*[a]
Frigento Field	1160	*123*	11.7	Sc	Yes

Italic indicates that using the site selection criteria discussed in the text, the reservoir property would render the reservoir unsuitable for CO_2 storage
[a]Seismically active fault, other faults are not known to be active
sc Supercritical

recommend CO_2 to be stored in supercritical state with reservoir temperatures of more than 35 °C at normal (~30 °C/km) temperature gradients, and reservoir pressures at more than 7.5 MPa. The caprocks should be "lateral extensive" (NETL 2010) with "minimal faulting" (Smith et al. 2011), effectively ruling out active faults. The capillary entry pressure of the caprocks should be greater than the pressure increase induced in the reservoir during CO_2 injection (Chadwick et al. 2008).

If these site selection criteria are used to screen the six insecure reservoirs, it becomes clear that all six of them would have been ruled out for failing at least one key selection criteria (Table 9.1). Three of the reservoirs hold CO_2 in gaseous state due to them being at shallow depths (400–700 m at St. Johns Dome; 500 m at Messokampos) or having reservoir pressures of less than 7.5 MPa with the reservoir being located at sufficient depth (7 MPa at 900 m depth, Farnham Dome). Two of the reservoirs are located in suitable depths and hold supercritical CO_2 but have very high temperatures (200 °C at 1000 m, Latera Caldera; 123 °C at 1160 m, Frigento Field). The last of the insecure reservoirs, Pieve Santo Stefano, is located very deep and has supercritical CO_2 at "normal" temperatures and pressures but is located next to a seismically active fault. The fact that all insecure natural reservoirs would have been detected by the selection criteria improves confidence that the internationally accepted selection criteria for engineered storage sites are effective in selecting storage sites which will be able to store CO_2 safely for the timescales required.

9.4 Geomechanical Facies Approach for Characterization

The subsurface is not a random collection of materials. Geological processes have led to structured deposits with distinct material characteristics and geometrical relationships. Processes have formed the geomechanical facies as a conceptual building block for the subsurface. A geomechanical facies has specific material characteristics defined by the geology of the rocks and defined by the engineering use to which it will be put. Using the geomechanical facies framework, the factors

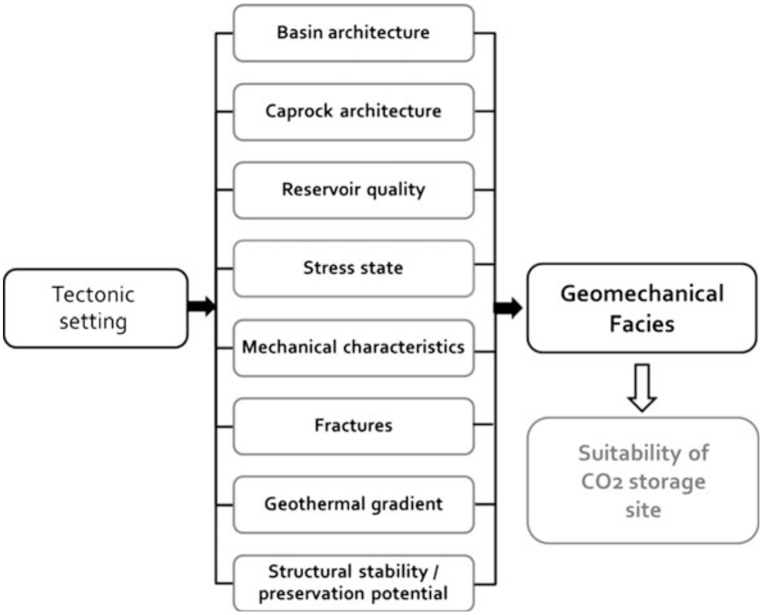

Fig. 9.8 Geomechanical facies parameters as controlled by tectonic setting (after Edlmann et al. 2015)

crucial to assessing the CO_2 storage security of a storage basin such as basin architecture, caprock architecture, reservoir quality, stress state, mechanical characteristics, fractures, burial depth, geothermal gradient, risk of orogenic modification, structural stability and preservation potential (Fig. 9.8) can all be taken into account.

By examining the typical characteristics of the geomechanical facies within the different tectonic settings, it is possible to compare and contrast the different tectonic settings to appraise global CO_2 storage opportunities and predict which tectonic settings will be most suitable for CO_2 storage.

It is important to note that the geomechanical facies approach for CO_2 site selection is the first step in what is a complex and iterative site specific assessment procedure, where uncertainty decreases as the data requirement increases. However this first appraisal step is a crucial stage in the identification and assessment of suitable CO_2 storage sites and underpins the later screening and ranking procedure of sedimentary basins for geological CO_2 storage (e.g. Bachu 2003).

Tables 9.2, 9.3, 9.4 and 9.5 show the results of a detailed analysis of the key parameters of sedimentary basins as determined by Edlmann et al. (2015) using the geomechanical facies approach along with an assessment of their net contribution towards ideal CO_2 storage conditions. These tables were used to apply the geomechanical facies approach to the CO_2 storage projects of Otway, Sleipner, In Salah, Snøhvit, Buracica and the natural CO_2 reservoirs of Miller, Fizzy and St. Johns.

Table 9.2 Summary of the key sedimentary stratigraphy, basin architecture, reservoir quality and caprock architecture as determined using the geomechanical facies approach, along with an assessment of their net contribution towards ideal CO_2 storage conditions

Key sedimentary stratigraphy and facies	Geomechanical facies assessment	
Extensional systems		
a. Oceanic basin		
Sedimentary stratigraphy	Pelagic sediments, fine grained clays and turbidites	
Basin architecture	Long narrow and straight. 10–100 km wide and >2000 km long	Good
Reservoir quality	Thin limited reservoir sands	Poor
Caprock architecture	Caprock muds and silts are extensive and thick	Good
b. Passive continental margin		
Sedimentary stratigraphy	Sedimentation dominated by mud, silt and fine sand laid down in thick sequences	
Basin architecture	Basin has distinct concave upwards base. Straight basins that are a few 10 km's wide and 1000's km long	Moderate
Reservoir quality	Reservoir sands are often extensive and thick	Good
Caprock architecture	Caprock muds and silts are extensive and thick	Good
c. Terrestrial rift basin		
Sedimentary stratigraphy	Sedimentation limited to material derived from neighbouring fault scarps and uplifted blocks. Dominant sediments are alluvial fans, lakes and marine. Fast filling and burial rates	
Basin architecture	Asymmetric geometry based along a boundary fault with a long narrow geometry. 10 km's wide and up to 2000 km long	Moderate
Reservoir quality	Thick rift basin bound or channelised reservoir sands	Moderate
Caprock architecture	Thick caprock muds and silts also rift basin bound or channelised	Moderate
Convergent systems		
a. Trench		
Sedimentary stratigraphy	Variable sedimentation, with trench fans, axial channel sandstones, non channelised sheet flow spreading over and down the trench and starved trench with only hemipelagic mud and turbidites deposited	
Basin architecture	Long and narrow basins that are concave towards the oncoming subducting plate. 10 km's wide and 1000's km long	Moderate
Reservoir quality	Reservoir sands rare and have highly non-predictable geometry	Poor
Caprock architecture	Caprock muds and silts will also have a non-predictable geometry	Poor

(continued)

Table 9.2 (continued)

Key sedimentary stratigraphy and facies	Geomechanical facies assessment	
b. Forearc basin		
Sedimentary stratigraphy	Clastic sedimentation predominates with turbidites and other mass flow deposits, marine sediments commonly grading into deltaic and fluvial sediments	
Basin architecture	Over 100 km wide and >2000 km long	Good
Reservoir quality	Reservoir sands will be thick but non-predictable geometry	Moderate
Caprock architecture	Caprock will also be thick but have non-predictable geometry	Moderate
c. Backarc basin		
Sedimentary stratigraphy	Thick clastic sedimentation predominates, there are pelagic sediments overlying newly formed basin crust; several thousand meters of turbidites in abyssal plains and continental shelves; shallow marine deposition and thick molasses type sediments	
Basin architecture	Small basins, no larger than km's wide and 10's kilometres long. They tend to be linear parallel to the trench	Poor
Reservoir quality	Reservoir sands can be complex and unpredictable	Moderate
Caprock architecture	Caprock muds and silts can be thick and extensive	Good
d. Foreland basin		
Sedimentary stratigraphy	Foreland basinsare filled with sediments that erode from the adjacent mountain belt. The width and depth of the foreland basin is determined by the flexural rigidity of the underlying lithosphere and the characteristics of the mountain belt	
Basin architecture	10's to a few 100 km's wide and 100's to 1000's of km long, varying profile reflecting the geometry of subduction	Good
Reservoir quality	Reservoir sands will be thick and extensive	Good
Caprock architecture	Caprock muds and silts are likely to be thick and extensive	Good
Wrench system		
a. Strikeslip pull apart basin		
Sedimentary stratigraphy	Typically the margins are sites of deposition of coarse facies alluvial fans and fan deltas and these pass laterally over short distance to lacustrine in continental settings or marine deposits	
Basin architecture	Rhomboidal shape elongating with time. km to a few 10's km wide and lengths of km to many 10's km	Moderate
Reservoir quality	Reservoir sands are thick and extensive	Good
Caprock architecture	Caprock muds and silts are thick and extensive	Good

Where an assessment of GOOD means that the input fulfils the ideal attributes of a storage reservoir, an assessment of MODERATE means it fulfils a reasonable number of the ideal attributes and a POOR assessment means it fulfils a low number of ideal attributes of a CO_2 storage reservoir

Table 9.3 Summary of the key stress state, fracture characteristics and geothermal gradient as determined using the geomechanical facies approach, along with an assessment of their net contribution towards ideal CO_2 storage conditions

Key stress state, fracture network and geothermal gradient	Reservoir and caprock quality	
Extensional systems		
a. Oceanic basin		
Stress state	On the stress ellipsoid, the maximum effective stress ($\sigma 1$) is in the vertical direction	
Fracture characteristics	Transform faults. Long near straight parallel fractures perpendicular to the ridge	Moderate
Geothermal gradient	Elevated geothermal gradient	Good
b. Passive continental margin		
Stress state	On the stress ellipsoid, the maximum effective stress ($\sigma 1$) is in the vertical direction	
Fracture characteristics	Normal faults, may flatten with depth	Good
Geothermal gradient	Elevated geothermal gradient	Good
c. Terrestrial rift basin		
Stress state	On the stress ellipsoid, the maximum effective stress ($\sigma 1$) is in the vertical direction	
Fracture characteristics	Normal faulting, commonly half graben with a single boundary fault	Moderate
Geothermal gradient	Average geothermal gradient	Moderate
Convergent systems		
d. Trench		
Stress state	Tectonic stress in a convergent system is characterised by a horizontal oblong stress ellipsoid with $\sigma 1$ in the horizontal direction	
Fracture characteristics	Normal faults, ocean ward of the subduction zone	Moderate
Geothermal gradient	Lower geothermal gradients due to the thrusting of cold, water-filled sediments beneath existing crust	Poor
e. Forearc basin		
Stress state	Tectonic stress in a convergent system is characterised by a horizontal oblong stress ellipsoid with $\sigma 1$ in the horizontal direction	
Fracture characteristics	There are multiple normal fault populations, with off sets of 20 m and dips of 60–70°	Poor
Geothermal gradient	Lower than normal geothermal gradients because of the cooling effect of the relatively cold subducting plate	Poor

(continued)

Table 9.3 (continued)

Key stress state, fracture network and geothermal gradient	Reservoir and caprock quality	
f. Backarc basin		
Stress state	Tectonic stress in a convergent system is characterised by a horizontal oblong stress ellipsoid with σ1 in the horizontal direction	
Fracture characteristics	Extensional faults which form due to the gravitational effects of the subducted crust	Moderate
Geothermal gradient	Lower than normal geothermal gradients because of the cooling effect of the relatively cold subducting plate	Poor
g. Foreland basin		
Stress state	Tectonic stress in a convergent system is characterised by a horizontal oblong stress ellipsoid with σ1 in the horizontal direction	
Fracture characteristics	Predominantly sedimentary wedges and thrust rather than deep faults	Good
Geothermal gradient	Cooler than normal geothermal gradient	Poor
Wrench system		
a. Strike slip pull apart basin		
Stress state	A tectonic stress field in which the maximum and minimum principal stresses σ1 and σ3 are orientated along the horizontal plane and the intermediate principal stress (σ2) is vertical	
Fracture characteristics	Faults range in size from plate boundaries to small scale fractures with only a few hundred meters or even just tens of centimetres of movement. Typical development of flower structure of normal and reverse faults. Rotations of small scalefault blocks	Moderate
Geothermal gradient	Elevated geothermal gradient	Good

Where an assessment of GOOD means that the input fulfils the ideal attributes of a storage reservoir, an assessment of MODERATE means it fulfils a reasonable number of the ideal attributes and a POOR assessment means it fulfils a low number of ideal attributes of a CO_2 storage reservoir

Table 9.4 Summary of the typical risk of overprint (stability), orogenesis modification and preservation potential as determined using the geomechanical facies approach, along with an assessment of their net contribution towards ideal CO_2 storage conditions

Extensional systems	
a. Oceanic basin	
Stability/ risk of overprint	Poor—high risk of overprint or destruction
Risk of major orogenesis modification	Poor—high risk of orogenesis modification
Preservation potential	Poor
b. Passive continental margin	
Stability/risk of overprint	Moderate risk of overprint or destruction
Risk of major orogenesis modification	Moderate risk of orogenesis modification
Preservation potential	Moderate
c. Terrestrial rift basin	
Stability/ risk of overprint	Moderate risk of overprint or destruction
Risk of major orogenesis modification	Good—low risk of orogenesis modification
Preservation potential	Good
Convergent systems	
a. Trench	
Stability/risk of overprint	Poor—high risk of overprint or destruction. Preserved portions will have collided and accreted onshore and are uplifted as mountain regions.
Risk of major orogenesis modification	Poor—high risk of orogenesis modification
Preservation potential	Poor
b. Forearc basin	
Stability/ risk of overprint	Moderate risk of overprint or destruction
Risk of major orogenesis modification	Poor—high risk of orogenesis modification
Preservation potential	Moderate
c. Backarc basin	
Stability/ risk of overprint	Moderate risk of overprint or destruction
Risk of major orogenesis modification	Moderate risk of orogenesis modification
Preservation potential	Moderate
d.Foreland basin	
Stability/ risk of overprint	Moderate risk of overprint or destruction
Risk of major orogenesis modification	Good—low risk of orogenesis modification
Preservation potential	Good

(continued)

Table 9.4 (continued)

Wrench system	
a. Strikeslip pull apart basin	
Stability/ risk of overprint	Poor—high risk of overprint or destruction
Risk of major orogenesis modification	Moderate risk of orogenesis modification
Preservation potential	Moderate

Where an assessment of GOOD means that the input fulfils the ideal attributes of a storage reservoir, an assessment of MODERATE means it fulfils a reasonable number of the ideal attributes and a POOR assessment means it fulfils a low number of ideal attributes of a CO_2 storage reservoir

9.5 Geomechanical Facies Models

Here we demonstrate the application of the geomechanical facies model on several contemporary storage sites, and also provide a generic overview of the sites including material parameters characterization.

9.5.1 Otway, Australia: CO_2 Storage Project

9.5.1.1 Extensional Terrestrial Rift Basin

The CO2CRC Otway Project Pilot Site, the largest demonstration project for geological CO_2 storage and monitoring in Australia, is located in the onshore portion of the Otway Basin, Victoria (Jenkins et al. 2012). Between March 2008 and August 2009 about 65,000 tons of gas, including 58,000 tons of CO_2, have been injected into a depleted, fault bound, natural gas field (Naylor Field). The sandstone reservoir of cretaceous age is in 2050 m depth and has an approximate thickness of 30 m with porosities of up to 30 % and high permeabilities of up to 1–5 Darcy (Dance et al. 2009). The sands are predominantly fluvial channels and tidal fluvial (reworked) sandstones. They are overlain by the 300 m thick Belfast Mudstone which is also the fault bound seal. The bounding faults terminate within the Belfast Mudstone and fluid migration into overlying aquifers is thus unlikely. The maximum horizontal stress orientation is NW–SE and is consistent with the maximum stress orientation in the Otway Basin. Geomechanical analysis shows that pore-pressures could be increased by 1–15.7 MPa, depending on assumptions made about stress magnitude, fault strength, reservoir stress path and Biot's coefficient, before faults would be reactivated (Vidal-Gilbert et al. 2010). Figure 9.9 presents the generic stratigraphy for the Otway CO_2 storage project.

Table 9.5 Summary overview of each of the assessed CO_2 storage component variable as determined by the geomechanical facies approach for each tectonic setting

Tectonic setting	Basin architecture	Reservoir quality	Caprock architecture	Fracture characteristics	Geothermal gradient	Stability/overprint	Orogenesis modification	Preservation potential
Oceanic basins	Good	Poor	Good	Moderate	Good	Poor	Poor	Poor
Passive continental margin	Moderate	Good	Good	Good	Good	Moderate	Moderate	Moderate
Terrestrial rift basins	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate	Good	Good
Trench basins	Moderate	Poor	Poor	Moderate	Poor	Poor	Poor	Poor
Fore-arc basins	Good	Moderate	Moderate	Poor	Poor	Moderate	Poor	Moderate
Back-arc basins	Poor	Good	Moderate	Moderate		Moderate	Moderate	Moderate
Foreland basins	Good	Good	Good	Good Poor	Poor	Moderate	Good	Good
Strike-slip basins	Moderate	Good	Good	Moderate	Good	Poor	Moderate	Moderate

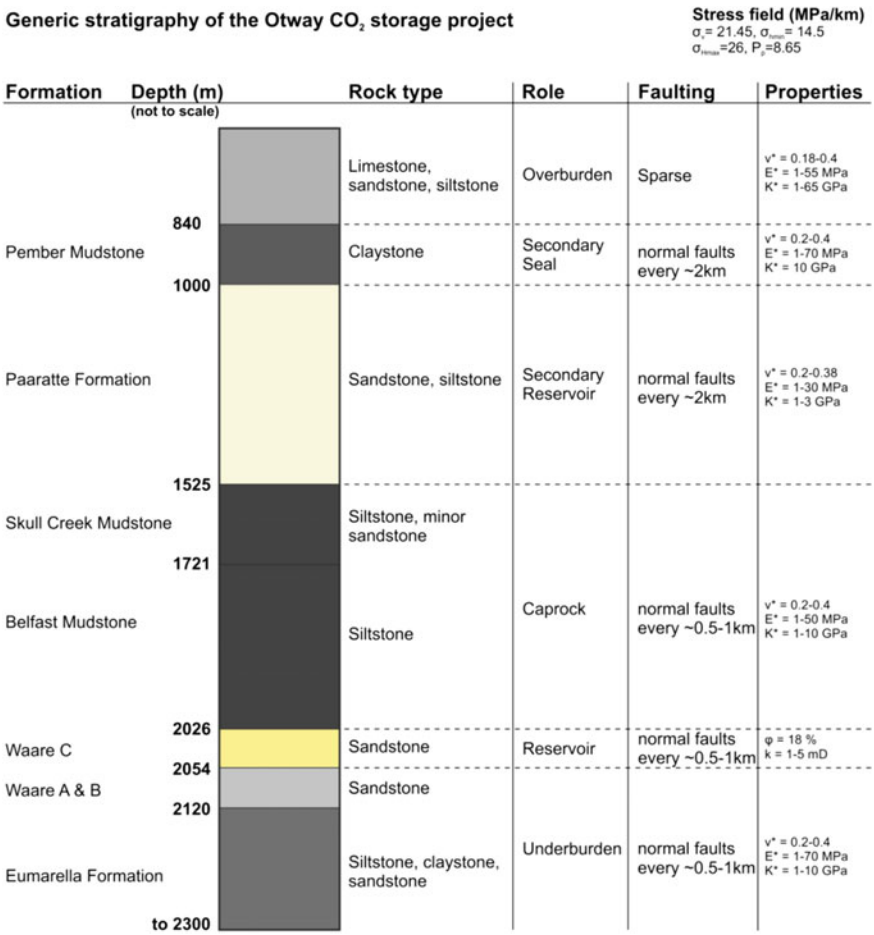

Fig. 9.9 Generic stratigraphy for the Otway CO_2 storage project. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, *φ* porosity, *k* permeability

9.5.1.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture, thick but channelized reservoir and caprock architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

The reservoir model and field operation data from the Otway CO_2 storage project exhibits a close first order predictive match with the geomechanical facies model, as summarized in Table 9.6.

Table 9.6 Summary of the match between the geomechanical facies storage potential prediction and the actual Otway field data

Otway	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extent	Faults	Preservation potential
Geomechanical facies prediction—*terrestrial rift basin*	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Elongated basin, reservoirs cut by faults	Fluvial and tidal sandstoneswith marine shales	30 m thick sandstone	300 m shale	Normal bounding faults	Little evidence of tectonic modification
Model/field data match	Good	Good	Moderate	Good	Good	Good

9.5.2 In Salah, Algeria: CO_2 Storage Project

9.5.2.1 Convergent Backarc Basin

The In Salah Gas Project, located in Algeria, is currently the world's largest onshore CO_2 storage site. The CO_2 is separated from natural gas produced from three nearby gas fields. CO_2 is injected into an underground saline aquifer of Carboniferous age through three wells. The storage formation is a tidal-deltaic Carboniferous sandstone overlain by about 900 m of mudstones and siltstones, which form the caprock (Bissell et al. 2011; Ringrose et al. 2011). The reservoir sandstone is approximately 20 m thick and extensively fractured with a predominant open fracture set (NW–SE). This is in close alignment with the present-day stress field, related to tectonic plate convergence between Africa and Eurasia. The storage formation is also segmented by strike-slip faults, indicative of a regional mid-to-late Carboniferous basin inversion (White et al. 2014). Surface deformation has been detected related to the CO_2 injection by DInSAR at In Salah (Onuma and Ohkawa 2009). Figure 9.10 presents the generic stratigraphy for the In Salah CO_2 storage project.

9.5.2.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with small linear basins, thick but complex reservoir architecture, thick caprocks with extensional fracturing. The basin will have moderate risk of overprint, moderate risk of orogenesis modification and moderate preservation potential.

The reservoir model and field operation data from the In Salah CO_2 storage project exhibits a close first order predictive match with the geomechanical facies model, as summarized in Table 9.7.

9.5.3 Sleipner, Norway: CO_2 Storage Project

9.5.3.1 Extensional Terrestrial Rift Basin

Sleipner is an offshore gas field in the mid- to eastern edge of the Viking Graben System of the North Sea. The Sleipner project is the first commercial application of storage in a deep saline aquifer in the world and CO_2 is injected into a sand layer called the Utsira formation which is a highly elongated sand reservoir, extending for more than 400 km from north to south and between 50 and 100 km from east to west. The Utsira sand is sparsely faulted and ranges in depth from 550 to 1500 m, the sand thickness is locally about 300 m and the regional top seal is a thick mudstones (Chadwick et al. 2012; Zweigel et al. 2004). It is interpreted as a basin restricted marine deposit. The caprock succession overlying the Utsira reservoir is

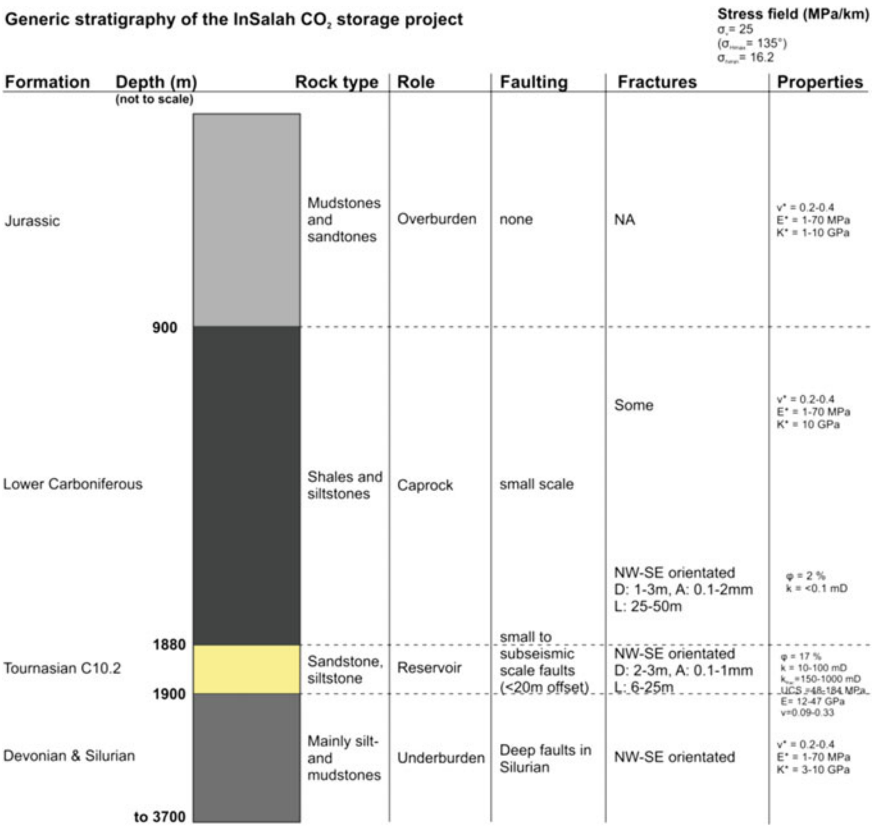

Fig. 9.10 Generic stratigraphy of the In Salah CO_2 storage project. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, φ porosity, *k* permeability, k_{frac} fracture permeability, *NA* no data available

100 m thick and variable and can be divided into three main units: the lower, the middle and the upper seals (Chadwick et al. 2004; Eiken et al. 2011; Harrington et al. 2009; Torp and Gale 2004). Figure 9.11 presents the generic stratigraphy for the Sleipner CO_2 storage project.

9.5.3.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture, thick but channelized reservoir and caprock architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

Table 9.7 Summary of the match between the geomechanical facies storage potential prediction and the actual In Salah field data

In Salah	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extent	Faults	Preservation potential
Geomechanical facies prediction—convergent backarc basin	Small basins linear parallel to the trench	Alluvial fans, lakes, turbidites, shallow marine and molasses deposits	Thick channelised sands	Thick caprocks	Extensional faults	Moderate preservation potential
Field data	Elongated reservoir	Tidal deltaic	Elongated sands, 20 m reservoir formation	900 m of caprock	Extensively fractured	Subject to regional Carboniferous basin inversion
Model/field data match	Good	Moderate	Good	Good	Good	Good

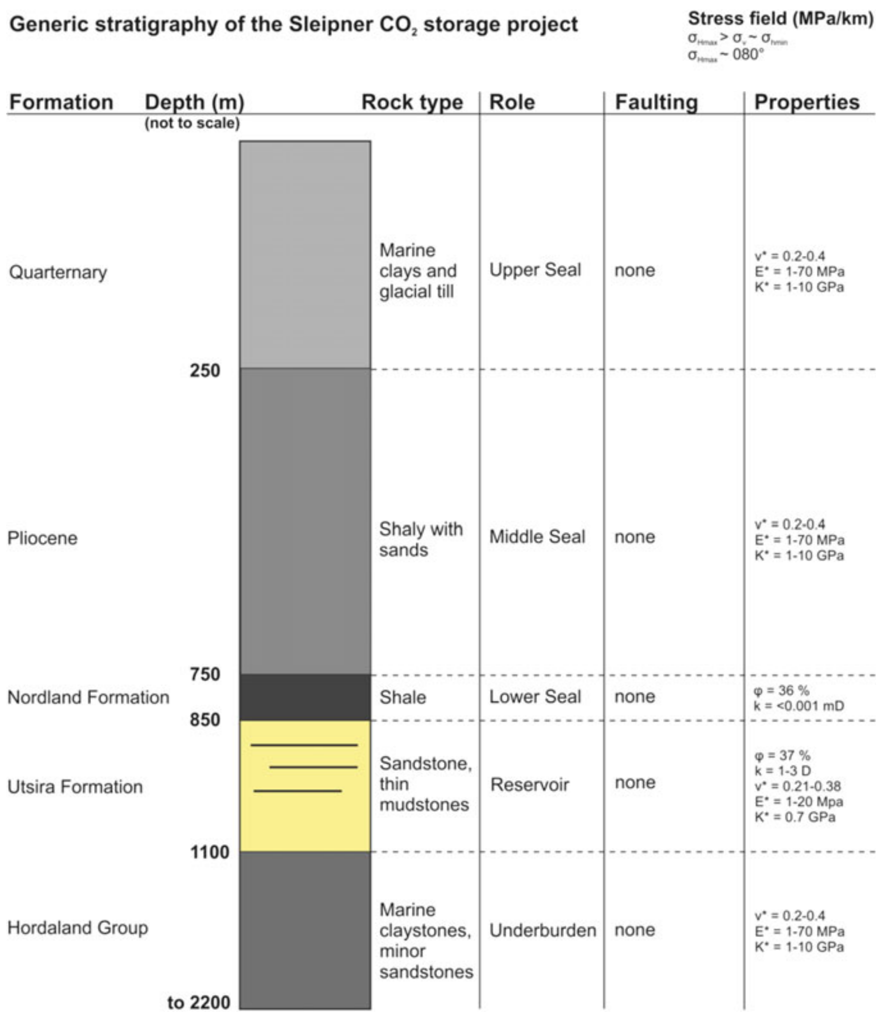

Fig. 9.11 Generic stratigraphy of the Sleipner CO_2 storage project. *Asterisk* indicates literature values instead of in-situ data. v Poisson's ratio, E Young's Modulus, K Bulk modulus, φ porosity, k permeability

The reservoir model and field operation data from the Sleipner CO_2 storage project exhibits a very close first order predictive match with the geomechanical facies model, as summarized in Table 9.8.

Table 9.8 Summary of the match between the geomechanical facies storage potential prediction and the actual Sleipner field data

Sleipner	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction—terrestrial rift basin	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Elongated reservoir	Basin restricted marine deposits	Elongated sands, about 300 m thick	The caprock is 100 m's thick and variable	Sparsely faulted	Little evidence of tectonic modification
Model/field data match	Good	Good	Good	Good	Good	Good

9.5.4 Snøhvit, Norway: CO_2 Storage Project

9.5.4.1 Extensional Terrestrial Rift Basin

The Snøhvit gas field is located in the Barents Sea, offshore northern Norway. Three gas reservoirs, operated by Statoil, are producing gas which is processed into LNG. It contains approximately 5–8 % CO_2 which is separated before liquefaction. The CO_2 is reinjected and stored in the early Jurassic Tubåen Formation at about 2600 m depth (Chiaramonte et al. 2011). Injection started in 2008 and is planned to continue for 30 years with a rate of 2000 tons/day. A total storage of 23 Mt is planned. The reservoir is formed by delta plain dominated fluvial distributary sandstones with some marine-tidal influence with a thickness of ~110 m and is located on fault blocks. The faults are ENE-WSW trending and have a maximum throw of <150 m (Hansen et al. 2013). Open fractures, dominantly with a N–S strike azimuth, are thought to locally influence fluid flow, however the reservoir quality of the sandstones with permeabilities in the range of 10–800 mD and porosities of 7–20 % is very high anyway (Wennberg et al. 2008). The local caprock is formed by the Nordmela Formation which has a thickness of 60–100 m and contains several shaly layers which are thought to act as flow barriers. Regional caprocks are formed by the thick marine shales of the Fulgen and Hekkingen Formations (Rodrigues Duran et al. 2013). Figure 9.12 presents the generic stratigraphy for the Snøhvit CO_2 storage project.

9.5.4.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture, thick but channelized reservoir and caprock architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

The reservoir model and field operation data from the Snøhvit CO_2 storage project exhibits a good first order predictive match with the geomechanical facies model, as summarized in Table 9.9.

9.5.5 Buracica, Brazil: CO_2 EOR

9.5.5.1 Extensional Terrestrial Rift Basin

The Buracica field is located in the Reconcavo Basin, a late Jurassic to early Cretaceous rift related basin, in the north–east of Brazil. CO_2 injection into the oilfield started in 1991 and until 2005 about 600,000 tons of CO_2 were injected into the reservoir which is a 9 m thick late Jurassic aeolian sandstone of the Sergi

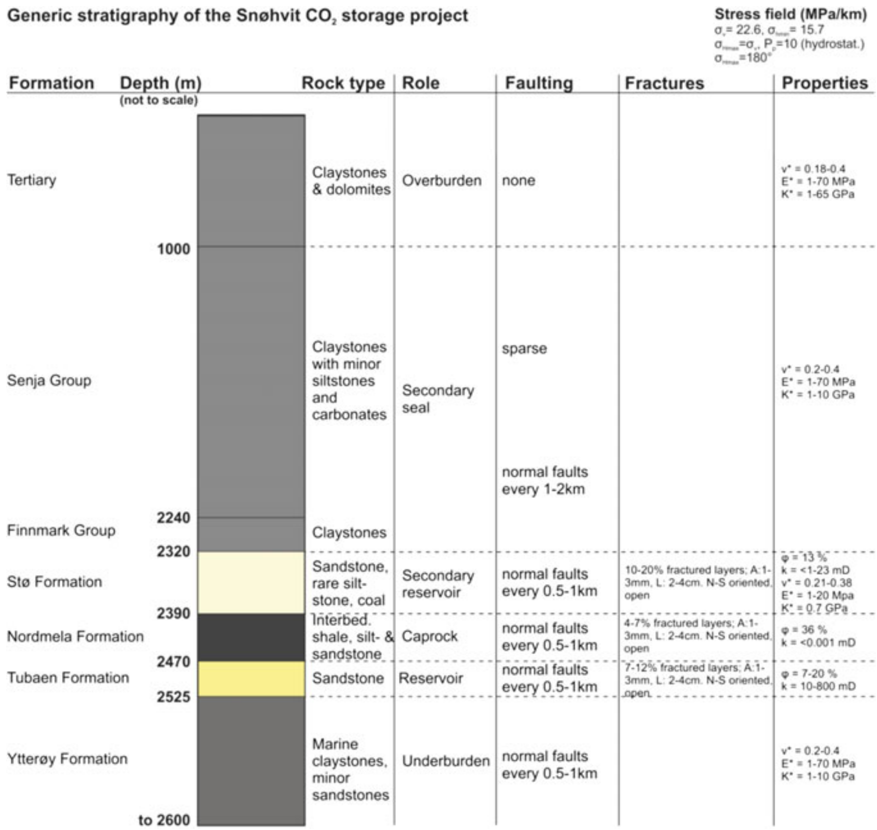

Fig. 9.12 Generic stratigraphy of the Snøhvit CO_2 storage project. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, *φ* porosity, *k* permeability

formation with an average porosity of 22 % and an average permeability of 570 mD (Estublier et al. 2011). Overall the reservoir formation is 200 m thick and consist of 14 aeolian and fluvial sandstone reservoirs that are separated by thin lacustrine deposits (Scherer et al. 2007). The reservoir is relatively shallow, with depths of 320–646 m below sea level (∼500–850 m below surface), is dipping with ∼6° south–eastward and has a lateral extend of 4.4 km in E–W direction and 3.2 km in N–S direction. At 470 m depth it has a temperature of 44 °C and an initial pressure of 5.5 MPa. The field is composed of three main tilted fault blocks with a maximum throw of about 150 m. The top seal is made of >150 m thick succession of early Cretaceous shales of the Itaparica and Taua formations (Hung Kiang et al. 1992; Rouchon et al. 2011). Figure 9.13 presents the generic stratigraphy for the Buracica CO_2 storage project.

Table 9.9 Summary of the match between the geomechanical facies storage potential prediction and the Snøhvit field data

Snøhvit	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction—terrestrial rift basin	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Elongated reservoir on horst structure	Fluvial and marine sandstones	Thick sands	Thick caprocks	Reactivated normal/reverse faults	Major phase of uplift in Pliocene/ Pleistocene
Model/field data match	Good	Good	Good	Good	Moderate	Moderate

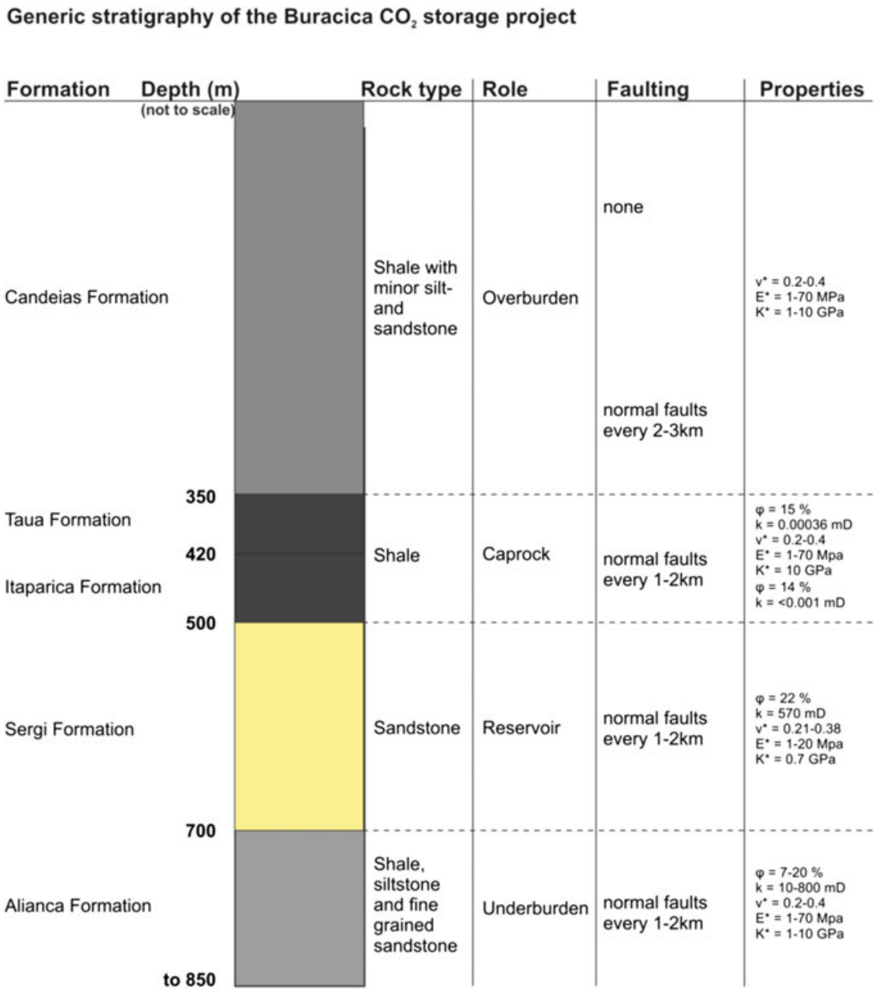

Fig. 9.13 Generic stratigraphy of the Buracica CO_2 storage project. *Asterisk* indicates literature values instead of in-situ data. v Poisson's ratio, E Young's Modulus, K Bulk modulus, φ porosity, k permeability

9.5.5.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture, thick but channelized reservoir and caprock architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

The reservoir model and field operation data from the Buracica CO_2 storage project exhibits a good first order predictive match with the geomechanical facies model, as summarized in Table 9.10.

Table 9.10 Summary of the match between the geomechanical facies storage potential prediction and the actual Buracica field data

Buracica	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction—terrestrial rift basin	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Elongate basin	Aeolian sandstone in alluvial environment, lacustrine shales	Overall thick sequence of fluvial and aeolian sands	Thick caprocks	Normal faults	Uplift in Tertiary
Model/field data match	Good	Good	Good	Good	Good	Moderate

9.5.6 Miller Field, UK North Sea: Natural CO_2 Reservoir

9.5.6.1 Extensional and Rotated Half-Graben Terrestrial Rift Basin

The Miller Field is located at the western margin of the north–south trending Viking Graben in the North Sea. It contains 28 mol% CO_2 and the reservoir and caprock have been exposed to these high concentrations of CO_2 since its emplacement and the CO_2 has been successfully stored for millions of years. The South Viking Graben is a half graben fault which is bounded against the west basement of the Fladen Ground Spur. Late Jurassic rifting and subsidence in the graben led to deposition of submarine fan systems which constitute the reservoirs in the Miller field (Eiken et al. 2011). It covers an area of 45 km^2 and shows limited faulting, faults in the Miller Field have NW–SE orientation (Rooksby 1991).

The Miller reservoir sandstones are composed of three main lithofacies. The first is clean, fine to medium-grained, well-sorted quartzose sandstone transported by, and deposited from sand-rich, high-density, low-efficiency turbidity currents. The second lithofacies is thinly bedded alternation of sandstone and mudstone, usually interbedded with the clean sandstones and deposits of the low-density turbidity currents. The third lithofacies is isolated mudstones locally interbedded with the main part of the reservoir, representing normal background sedimentation at the margins of the fan system, or during periods of non-deposition within the fan (Lu et al. 2009). During the period of highest sea level the Kimmeridge Clay Formation covered the Miller Field reservoir sands and formed a seal over the field with a thickness of several hundreds of meters. Figure 9.14 presents the generic stratigraphy for the Miller field natural CO_2 reservoir.

9.5.6.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

The reservoir model and field operation data from the Miller natural CO_2 reservoir exhibits a close first order predictive match with the geomechanical facies model, as summarized in Table 9.11.

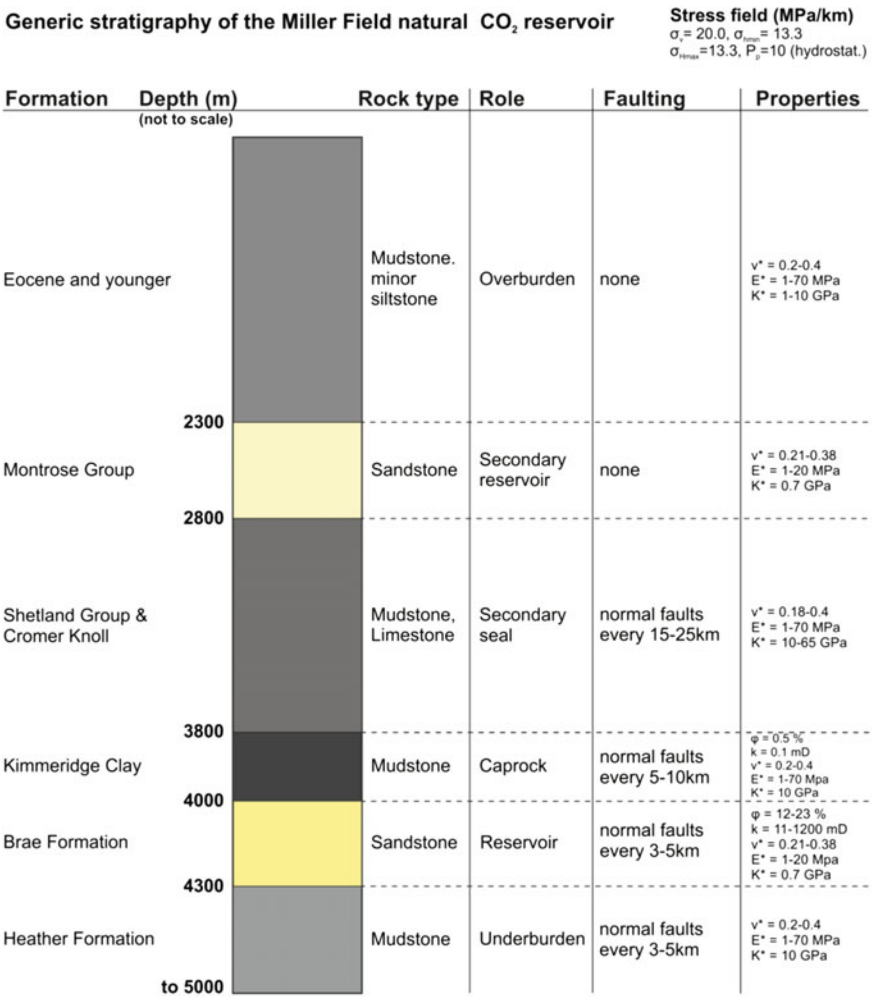

Fig. 9.14 Generic stratigraphy of the Miller field natural CO_2 reservoir. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, *φ* porosity, *k* permeability

9.5.7 St. Johns Dome, USA: Natural CO_2 Reservoir

9.5.7.1 Possible Foreland Basin

The natural CO_2 field of St. Johns is located in North–Eastern Arizona at the southern end of the Permian Holbrook basin and the southern edge of the Colorado Plateau (Blakey 1990; Rauzi 1999). The mechanism of basin subsidence of non-yoked Permian basins on the Colorado Plateau and Southern Rocky Mountains

Table 9.11 Summary of the match between the geomechanical facies storage potential prediction and the actual Miller field data

Miller	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction—terrestrial rift basin	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Small basin, covers an area of 45 km^2	Turbidite deposits	Thick sands followed by thick interbedded sands/muds	Thick caprock deposits	Limited faulting	Moderate preservation
Model/field data match	Good	Moderate	Good	Good	Good	Good

is hard to determine as the Late Paleozoic tectonics were subtle (Blakey 2008). The reservoir rocks of the Permian Supai Formation are dominantly siltstones, fine grained sandstones and carbonate layers and are in depth between 300 and 700 m below surface and have an approximate thickness of ~400 m. Continuous, thin anhydrite layers form seals within the reservoir complex and the top seal is formed by shales of the upper Supai formation, Permian limestones of the San Andres Formation and Triassic shales of the Moenkopi and Chinle Formations which have a total thickness of ~300 m. The CO_2 is mantle sourced and is probably related to the nearby Springerville volcanic complex (Gilfillan et al. 2011). CO_2 has been encountered in fractured Precambrian Granite which forms the basement (Embid 2009). Structurally the reservoir is located in a faulted anticline. It's spatial extent is ~60 × 35 km. The St. Johns Dome area is well known for its extensive travertine deposits which record a history of CO_2 leakage from the reservoir over the last 400 ka (Priewisch et al. 2014). Figure 9.15 presents the generic stratigraphy of the St. Johns Dome natural CO_2 reservoir.

9.5.7.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a good storage opportunity with a long and wide basin architecture, with thick reservoir sands and extensive caprocks with few fractures. The basin will have a cool geothermal gradient, a moderate risk of overprint or destruction, low risk of orogenesis modification and a good preservation potential.

The reservoir model and field operation data from the St. Johns Dome natural CO_2 reservoir exhibits a moderate-poor first order predictive match with the geomechanical facies model, as summarized in Table 9.12. This might indicate that the basin type has not correctly been identified.

9.5.8 Fizzy Field, UK Southern North Sea: Natural CO_2 Reservoir

9.5.8.1 Post Extensional Terrestrial Rift Sag Basin

The Fizzy field is located in block 50/26b of the UK sector of the southern North Sea and is part of the Southern Permian Basin (SPB) complex. The SPB is a major east–west striking sedimentary basin that has hosts the majority of gas and oil fields of the UK, the Netherlands, Denmark and Germany (Glennie 1998). The reservoir consists of Permian aeolian Rotliegend sandstones with a thickness of 100 m and good reservoir quality (18 % porosity and 260 mD permeability) and holds a gas column of 50 % CO_2, 41 % CH_4 and 9 % N_2 (Underhill et al. 2009). About 550 m of Permian evaporites (mainly anhydrite, minor salt and carbonates) and Triassic

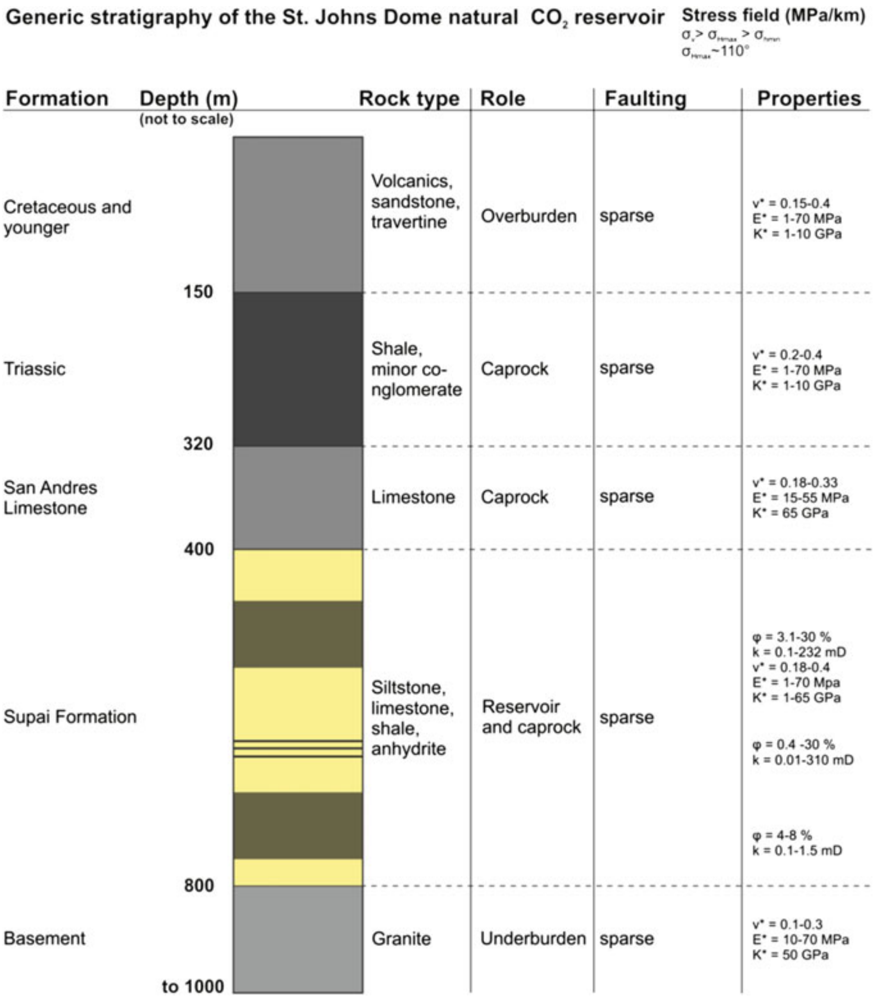

Fig. 9.15 Generic stratigraphy of the St. Johns Dome natural CO_2 reservoir. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, *φ* porosity, *k* permeability

shales form the top seal. The reservoir is located on a horst structure and is fault bound, with the bounding fault having a maximum throw of 500 m (Yielding et al. 2011). The fault has been reactivated and inverted during the Late Cretaceous, todays stress field is probably a strike-slip faulting regime. Figure 9.16 presents the generic stratigraphy of the Fizzy Field natural CO_2 reservoir.

Table 9.12 Summary of the match between the geomechanical facies storage potential prediction and the actual St. Johns Dome field data

St. Johns	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction—foreland basin	Wide to very long basin with varying profile	Filled with mountain belt material, alluvia, fluvial and lake deposits	Thick and extensive sands	Thick and extensive caprocks	Predominantly thrusts rather than deep faults	Good preservation potential
Field data	Big reservoir (10 s of km)	Mainly redbeds with possible marine carbonates	Thick siltstones and fine sands	Thick caprocks	Deep seated faults	Extensive uplift and overprinting
Model/field data match	Good	Good	Moderate	Good	Poor	Poor

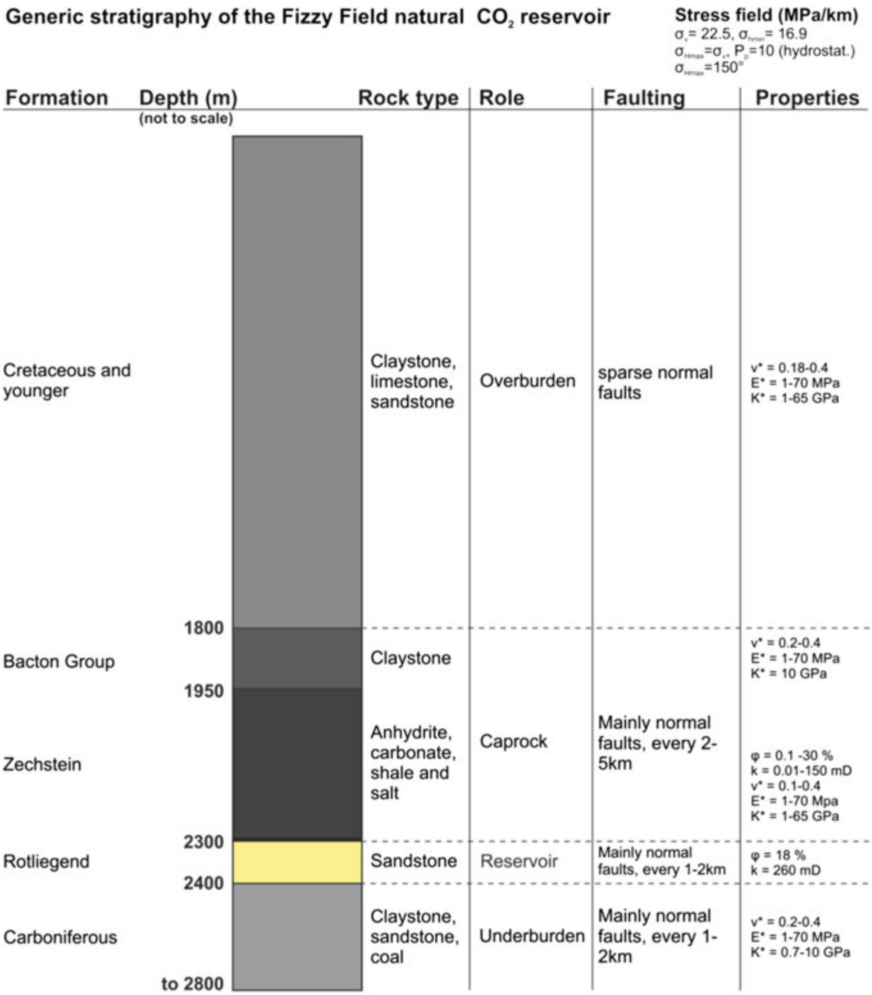

Fig. 9.16 Generic stratigraphy of the Fizzy Field natural CO_2 reservoir. *Asterisk* indicates literature values instead of in-situ data. *v* Poisson's ratio, *E* Young's Modulus, *K* Bulk modulus, *φ* porosity, *k* permeability

9.5.8.2 Geomechanical Facies Model

The geomechanical facies model would predict this to be a moderate storage opportunity with long narrow basin architecture, thick but channelized reservoir and caprock architecture and few fractures. The basin will have low risk of overprint, low risk of orogenesis modification and good preservation potential.

The reservoir model and field operation data from the Fizzy Field natural CO_2 reservoir exhibits a close first order predictive match with the geomechanical facies model, as summarized in Table 9.13.

Table 9.13 Summary of the match between the geomechanical facies storage potential prediction and the actual Fizzy field data

Fizzy	Basin architecture	Sedimentary stratigraphy	Reservoir potential	Caprock extend	Faults	Preservation potential
Geomechanical facies prediction–terrestrial rift basin	Long narrow geometry	Alluvial fans, lakes and marine deposits	Thick channelized sands	Thick caprocks	Single boundary normal faults	Good preservation potential
Field data	Elongated reservoir	Aeolian sandstones, lake and marine deposits	Thick dune sands	Thick caprocks	Reactivated normal faults	Moderate preservation
Model/field data match	Good	Good	Moderate	Good	Moderate	Moderate

9.6 Conclusions

A total of 61 natural analogue CO_2 storage sites where investigated and the key geological and physical controls on ensuring the longer term retention of CO_2 were identified. These controls were then related to different characteristics of the geomechanical facies within the storage system. The geomechanical facies are identified as combinations of geological facies operating in a specific engineering way, e.g. storage, retention or overburden.

The characteristics of the different geomechanical facies are controlled by the tectonic settings they were deposited in. This directly influences sediment stratigraphy, thickness and the distribution of the caprock and reservoir sediments. The tectonic setting also determines basin architecture, stress state, mechanical properties, fracture characteristics, burial depths, geothermal gradient, structural stability and preservation potential, all crucial inputs into assessing CO_2 storage site suitability.

Using the geomechanical facies approach, the geomechanical facies inputs crucial to the primary CO_2 storage requirements of storage volume and storage security can be evaluated and graded as good, moderate and poor based on an assessment of their net contribution towards providing ideal CO_2 storage conditions.

The results show that foreland basins and passive continental margin basins are very suitable basins for CO_2 storage. Strike-slip basins, terrestrial rift basins and back arc basins are also suitable for CO_2 storage with oceanic basins and fore-arc basins being moderately suitable and trench basins unsuitable tectonic settings for CO_2 storage.

The geomechanical facies approach was then used to evaluate a number of current anthropogenic CO_2 storage projects and natural CO_2 storage analogues. Generic conceptual profiles are presented for the sites and the main hydraulic and mechanical parameters for the different geomechanical facies in each site is presented. The sites include Otway-Australia, In Salah-Algeria, Buracica-Brazil, Sleipner-Norway, Snøhvit-Norway, Miller Field-UK North Sea, Fizzy Field, UK Southern North Sea and St. Johns Dome-USA.

Using the geomechanical facies framework to evaluate the storage potential correctly predicts that most of the sites would be suitable CO_2 storage opportunities. Only in cases where there has been significant overprint of the original basin architecture (e.g. Snohvit) or where the basin type is not well known (St. Johns) the approach has limitations.

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