CO₂ Migration and Pressure Evolution in Deep Saline Aquifers

Jens T. Birkholzer, Curtis M. Oldenburg, Quanlin Zhou
Lawrence Berkeley National Laboratory

Corresponding Author: Jens T. Birkholzer
jtbirkholzer@lbl.gov

Abstract

In 2005, the IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS) summarized the state of knowledge about CCS as an emerging technology for reducing CO₂ emissions to the atmosphere. At the time of writing, the emphasis of the SRCCS was on understanding the fate of injected CO₂ whereas less attention was paid to effects of pressure buildup associated with CO₂ injection. Since then, the CCS community has significantly improved the knowledge base and addressed many of the technical gaps mentioned in 2005. A large body of research has been devoted to identify and verify the main processes that control CO₂ migration, trapping, and containment in deep saline aquifers. Much work has also been conducted to better understand the magnitude and implications of reservoir pressure buildup in response to large CO₂ storage projects. The aim of this paper is to provide a summary and overview of the most relevant recent (since publication of the IPCC SRCCS) literature and findings in the areas of CO₂ migration and pressure evolution. The paper first summarizes recent findings related to CO₂ plume migration and trapping, based on analytical and numerical modeling studies as well as several field injection tests conducted to examine the fate of injected CO₂ in various subsurface settings. The paper then discusses pressure effects as a function of space and time, including the effects of confinement (boundary conditions), highlights possible unwanted pressure impacts such as pressure-driven leakage and geomechanical damage, analyzes potential capacity constraints, reviews current concepts for pressure management, and closes with a discussion about use of pressure signals for advanced monitoring.

1. Introduction

Carbon dioxide (CO₂) capture and storage (CCS) entails separating CO₂ from the large-scale atmospheric releases of flue gases from industrial sources, such as coal-fired power plants, compressing it to a denser supercritical form (scCO₂), transporting it via pipeline to where suitable geology is found, injecting it deep underground, and storing it permanently in geological reservoirs. In 2005, the IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS) summarized the state of knowledge about CCS as an emerging technology for reducing CO₂ emissions to the atmosphere (IPCC, 2005). The Special Report, which raised the profile of CCS among technical experts and climate policy makers, clearly indicated that capturing and storing CO₂ underground is in principle technically feasible, and that total capacity of the subsurface for storing CO₂ is more than sufficient. It was also recognized at the time of writing of the SRCCS that the literature on CCS was limited but growing rapidly. The objective of this paper is to review the literature since the time of publication of the Special Report, with emphasis on CO₂ plume behavior and pressure buildup in deep saline aquifers used for CO₂ storage.

At the time of finalizing the SRCCS in 2005, three industrial-scale CCS projects were in operation, two of which are ongoing today. The Sleipner Project had been injecting CO₂ at an average rate of about ~1 million tonnes (Mt) per year in an offshore saline formation in Norway since 1996 (Korbøl and Kaddour, 1995; Baklid et al., 1996). The Weyburn Project in Canada was initiated in 2000 as a CO₂ Enhanced Oil Recovery (EOR) project with the ultimate goal of storing millions of tonnes of CO₂ towards the end of the oil field life (Preston et al., 2005). The In Salah Project in Algeria had just started operation in 2004 with the goal of injecting more than one Mt of CO₂ annually into a thin low-permeability formation (Mathieson et al., 2010; Wright et al., 2010). As these projects were demonstrating feasibility of CCS at a considerable scale, several smaller pilot and demonstration projects were under way or in planning stages to target specific research topics, such as the feasibility of monitoring CO₂ deep underground or the characteristics of CO₂ migration in different geologies and hydrostratigraphic conditions. One example was the Frio Project conducted in October 2004, which involved injection and storage of about 1,600 tonnes of CO₂ in a regionally extensive formation underlying the Texas Gulf Coast (Hovorka et al., 2006). Other pilot tests were proposed at the time for Ketzin, Germany (Würdemann et al., 2010), and for the Otway Basin in southeast Australia (Underschultz et al., 2011). Meanwhile, in 2003 the U.S. had launched its nationwide network of seven federal, state, and private-sector regional partnerships to determine the most suitable technologies, regulations, and infrastructure for CCS in different areas of the country (Litynski et al., 2009; Rodosta et al., 2011; Litynski et al., 2013). When the SRCCS was published, the partnerships were in the first phase of the program, characterizing the potential for CO₂ storage in deep oil-, gas-, coal-, and saline-bearing formations. Later program phases focused on confirming and validating regional sequestration opportunities through a series of small-scale geological pilot tests (less than 500,000 tonnes total) and several large-scale (one Mt or more total) demonstration projects for geologic storage and utilization.

Today, 10 years later, the CCS community has significantly improved the knowledge base and addressed many of the technical gaps mentioned in 2005. Several pilot and demonstration projects have provided valuable information on the migration, trapping, and containment of injected CO₂ in a range of geological settings, while demonstrating ways of monitoring it. In the United States alone, nineteen small-scale geologic pilot tests have been conducted by the regional partnerships with a total of 1 Mt of CO₂ injected as of summer 2014 (<http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/rcspii>), and eight large-scale demonstration experiments are ongoing or in planning stages (<http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/regional-partnership-development-phase-iii>). As of late 2014, the large-scale demonstration projects in the United States have stored over 7.2 million Mt of CO₂ in various

geologic formations. Important research projects have also been conducted outside the U.S., such as the pilot tests at Ketzin and Otway, and the Shenhua Ordos demonstration project in China. Section 2 in this paper describes what has been learned since 2005 regarding CO₂ plume migration and trapping, based on these field experiments and the substantial body of modeling and laboratory work associated with these.

Meanwhile, the world is moving very slowly from demonstration to industrial-scale implementation of CCS. According to the project status list published by the Global CCS Institute (GCCSI, 2014), as of February 2014, there are now twelve large-scale to industrial-scale CCS projects in operation globally, nine under construction, and another 39 in various stages of development and planning. As stated in GCCSI (2014), the 21 projects in operation or under construction represent a 50% increase since 2011, as North America is leading the implementation of CCS and China quickly gaining importance. The Sleipner and Weyburn Projects have been in continuous operation since their inception, while the In Salah Project operated from 2004 through 2011 and the Snøhvit Project in Norway started injection in 2008. Other prominent industrial-scale CCS projects recently brought online or in final construction/execution phases include the following: the Boundary Dam Integrated Carbon Capture and Sequestration Project in Canada (started in 2014 to capture about 1 Mt of CO₂ annually, primarily for EOR), the Illinois Industrial CCS Project in the USA (starting in 2015 will capture and store about 1 Mt of CO₂ annually), the Kemper County IGCC Project in the USA (starting in 2016 will capture about 3 Mt of CO₂ annually, primarily for EOR), and the Gorgon Carbon Dioxide Injection Project in Australia (starting in 2016 will capture and store 3.4 to 4 Mt of CO₂ annually).

As can be seen from the increasing annual injection rates of planned projects, future industrial-scale CCS operations may involve injection rates and total storage volumes that dwarf most of the past or ongoing CO₂ injections. It was not realized at the time of the SRCCS that projects of those dimensions can cause large-scale pressure changes and basin-scale brine displacement in saline aquifers. For example, an industrial-scale CO₂ storage project for a large coal-fired power plant of 1,000 MWe generation capacity (enough electricity for approximately one million people) can generate, over a typical power-plant lifetime, a subsurface CO₂ plume with linear dimensions of perhaps 10 km, while pressurization of more than 0.1 MPa could occur over basin-scale regions with dimensions of 100 km and more (Pruess et al., 2003). In a future world with CCS being a fully deployed technology, sedimentary basins with interconnected reservoirs might host multiple storage sites, in which case pressure interference could be expected between individual projects (Birkholzer and Zhou, 2009; Zhou et al., 2010).

That the SRCCS did not fully recognize reservoir pressurization as a potential limiting factor for CO₂ deployment may have been related to the nature of two industrial-scale projects ongoing in 2005. Neither project experienced substantial pressure effects—the Sleipner Project because CO₂ was injected into a sand formation with exceptionally high permeability, and the Weyburn Project because oil was produced as CO₂ was injected (Verdon et al., 2013). Since then, however, significant research has been conducted to better understand pressure effects as a function of space and time (Nicot, 2008; Zhou et al., 2008; Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Yamamoto et al., 2009; Zhou et al., 2010; Person et al., 2010; Zhou and Birkholzer, 2011; Huang et al., 2014). Researchers have paid more attention to the large-scale pressure responses expected for future industrial-scale carbon sequestration and evaluated possible unwanted pressure impacts such as pressure-driven leakage and geomechanical damage. The In Salah Project, which started CO₂ injection in 2004, demonstrated that pressurization could be a real concern for reservoir and caprock integrity (Vasco et al., 2010; Morris et al., 2011; Rinaldi and Rutqvist, 2013; Verdon et al., 2013). Section 3 in this paper summarizes the state-of-the-art knowledge about the magnitude and implications of reservoir pressure buildup in response to large CO₂ storage projects.

2. CO₂ Migration and Trapping

2.1. Background and Scope

The main processes critical to successful storage of CO₂ were well understood in 2005 and described in Chapter 5, Section 5.2 of the SRCCS (IPCC, 2005). Briefly, starting from the injection well, it was understood that CO₂ will enter the formation during injection at high flow rates through perforations in the well casing, flow relatively vigorously into the most permeable regions surrounding the well under strong pressure gradients while displacing native fluids (e.g., brine), respond to existing and induced hydraulic gradients farther away from the well (including buoyancy, which will tend to drive CO₂ upward), flow under strong control of permeability heterogeneity by pressure gradients and buoyancy forces, and be influenced by capillary exclusion processes as the nonwetting fluid invades the wetting fluid (brine). Many storage formations will feature thick low-permeability seals (caprocks), such as very-low-permeability shale or salt beds, as the principal (stratigraphic or structural) mechanism for trapping buoyant CO₂. Longer-term processes such as large-scale residual phase trapping, dissolution into formation fluid, and mineral trapping would follow the main plume emplacement and migration phase over years to millennia. Although idealizing a CO₂ plume in a deep formation into three main regions (dryout, two-phase scCO₂-brine, and single-phase brine) is still useful for developing analytical solutions and understanding fundamental controls on flow (e.g., as depicted in Figure 2.1), the importance of intra-formation heterogeneity, dissolution, and residual phase trapping in affecting plume migration and trapping was emphasized already in 2005 as evidenced by the three figures in Section 5.2 of the SRCCS (Figures 5.6, 5.7, and 5.8). Since 2005, a great deal of research has been carried out to further investigate, evaluate, and confirm the expected processes and controls affecting CO₂ migration and trapping. Along the way, some new processes and effects have been identified which are important contributions to the CCS knowledge base.

In order to keep the review of advances in CO₂ plume migration and trapping since 2005 to a reasonable length, we focus here on research advances in field-scale processes that have arisen from analytical, numerical, and field studies. Although some people might have justifiably believed in 2005 that there would be numerous industrial-scale CCS projects around the world by 2015 (e.g., IEAGHG, 2002; IEA, 2004), the fact is that much of the available field experience with CCS has come from small-scale injection tests. This situation has created something of a golden age for numerical modeling that is heavily relied upon for studying the physical and chemical processes of large-scale geologic storage of CO₂ (e.g., Pruess et al., 2004; Class et al., 2009). Advances in numerical modeling of CO₂ plume migration and trapping since 2005 have been in high-resolution simulations with parallel computing to reduce grid effects and to match field-scale plumes observed through geophysical and wellbore monitoring at storage sites (e.g., Hosseini et al., 2013; Senel et al., 2014), and in analysis of prediction uncertainties caused by approximations of numerical modeling (e.g., Nordbotten et al., 2012) and uncertainties of rock properties (e.g., Ashraf et al., 2013; Wainwright et al., 2013). The last ten years have also been a prodigious time for analytical and mathematical modeling, as numerous solutions have been developed since 2005 to predict two-dimensional radial CO₂ plume migration for a single well injection using the sharp interface approximation (e.g., Nordbotten et al., 2005; Nordbotten and Celia, 2006; Dentz and Tartakovsky, 2009), or to predict the one-dimensional CO₂ saturation profile with leading and trailing sharp fronts using the Buckley-Leverett fractional flow theory (e.g., Burton et al., 2008; Azizi and Cinar, 2013). The most recent one-dimensional solution (Mijic et al., 2014) can account for two-phase fractional flow, miscible phase partitioning for dryout and dissolution, CO₂ compressibility, and even non-Darcy gas flow in the dryout zone. These analytical solutions have furthered our understanding of CO₂ migration and trapping by correlating the extent and shape of CO₂ plumes with fluid and rock properties through

simple functions and dimensionless numbers, and have been developed into screening tools for simplified storage systems (e.g., Mathias et al., 2009; Okwen et al., 2010).

At the same time, increasing numbers of pilot- and demonstration projects have allowed researchers to significantly improve our understanding of CO₂ migration and trapping in naturally heterogeneous storage formations. These projects have been carried out in a variety of storage formations and initial pressure and temperature conditions, and may be more representative of the future large-scale deployment of geological carbon storage (GCS) than the Sleipner Project that was already well studied in 2005. The intra-formation heterogeneity, whose effects have been studied through field monitoring, remains a challenge currently being addressed through process-based forward modeling and data-based inverse modeling, as researchers utilize and evaluate the wealth of information provided from these projects (e.g., Doetsch et al., 2013; Hosseini et al., 2013; Senel et al., 2014).

In the following sub-sections, we consider analytical, mathematical, and numerical modeling, along with field experiments, as we review the most important findings and capability developments in the areas of CO₂ migration and trapping, starting from the wellbore and extending out to the edge of the CO₂ free-phase plume. In Figure 2.1, we show the three general regions of phase occupancy around a CO₂ injection well that are useful for delineating the different domains in which different processes will be dominant. Although very important in the two-phase region, we deliberately avoid reviewing dissolution trapping, geochemical reactions, mineral trapping, storage efficiency factors, and laboratory-scale research (e.g., on residual-phase trapping), in deference to other papers in this Special Issue that are focused on these topics.

Figure 2.1. The injection well, dryout zone, two-phase CO₂-brine zone, and single-phase brine flow zone depicted for a 1D radial system (from Aziz and Cinar, 2013). The symbols: r_{dry} , r_{BL} and r_e are the radius of the dryout zone, the two-phase Buckley-Leverett fractional flow zone, and the model domain, respectively, and S_{gdry} and S_{gBL} are the CO₂ saturations at the two sharp fronts.

2.2. Analytical, Mathematical, and Numerical Process Modeling

2.2.1. Near-Well Plume Processes

The injection well and near-well regions sustain high flow rates of CO₂ during injection, which drive short time-scale processes very different from the far-field region. For example, during injection there is feedback between the wellbore and the formation arising from injectivity changes such as those caused by local formation damage, drying, or precipitation of halite. The term “injectivity” describes the ability to inject CO₂ at a given rate at a safe injection pressure, and can be described dimensionally as the mass of CO₂ injected per unit time per unit of pressure rise. Injectivity can be assessed by means of an injectivity test (e.g., Schlumberger online glossary). In 2005, the injection process was typically modeled using a constant-pressure boundary condition to represent a well screen, or by using a specified mass-source injection rate to represent flow from the well. Although

both of these approaches may be adequate depending on the question being addressed, neither one of these approaches represents the actual coupled flow process of wellbore fluid entering the geologic formation. An advance in this area was made through the coupled numerical modeling of turbulent fluid flow in the well with the porous media flow in the formation. The approach implements a drift-flux model for one- or two-phase viscous flow in the well and couples this directly with two-phase porous media (Darcy) flow in the formation (Pan, 2011). By this approach, pressurization effects in the reservoir feed back into the wellbore, allowing assessment of fundamental questions such as whether the low pressure of a depleted gas reservoir will propagate into the injection well and thereby limit injection rate resulting from lowering the density of the CO₂. For this problem, it was found that the pressure in the reservoir around the well rises rapidly due to injection, obviating the need for a down-hole choke, but that subcritical conditions persist at the bottom of the well for ~200 days for the specific studied case (Pan et al., 2011). Wellbore-only models or wellbore models coupled to simple models of the formation have also been developed (Lu and Connell, 2008; 2014) as have fully coupled models that do not consider friction losses in the wellbore (White et al., 2013). With growing interest in horizontal wells for CO₂ injection, there will be a need for additional advances in coupled wellbore-reservoir modeling.

Just outside of the wellbore is a region that sustains long-term high flow rates of CO₂ from the well during injection (see Figure 2.1). Researchers considering the injection process recognized prior to 2005 that injected CO₂ tends to dry out the formation (Pruess and Garcia, 2002). This process offers the benefit of increasing the relative permeability of CO₂, but also the potential downside of precipitation of salt left behind by the evaporating water, which can reduce formation permeability. Further studies on both dryout and salt precipitation processes after 2005 include both analytical solutions (Pruess, 2009; Zeidouni et al., 2009) and numerical modeling (e.g., Giorgis et al., 2007; Hurter et al., 2007). To account for the potential to reduce permeability through halite precipitation by the dryout process, numerical simulation has suggested that a brief pre-flush of water may be useful in dissolving and transporting salts farther from the well and thereby avoiding injectivity loss (Pruess and Mueller, 2009). In addition, simulation studies have shown that high-permeability fill materials could be emplaced between the perforated casing and the formation to mitigate halite-precipitation-induced injectivity loss (Kim et al., 2012). Finally, recent modeling of non-Darcy flow effects in the near-well region suggests that halite precipitation may not be as large as previous Darcy-flow models have suggested (Mijic et al., 2014).

Another potential effect on CO₂ injection relevant in the near-well region is thermal perturbation induced by the difference between formation temperature and the flowing CO₂ temperature as well as the effect of Joule-Thomson cooling induced by CO₂ expansion. In brief, CO₂ leaves the wellbore at very high pressure and decompresses as it enters the formation, resulting in the potential for decompression cooling. Decompression cooling is especially important in the case of CO₂ injection into a depleted (low-pressure) gas reservoir. Post-2005 numerical simulation and analytical studies have shown the effects of decompression cooling to be relatively minor (a few °C), owing to the heat contained in the solid matrix grains and the continued supply of enthalpy from the injectate stream (Oldenburg, 2007; Mathias et al., 2010; Singh et al., 2011). A detailed analysis of the myriad thermal effects associated with CO₂ injection and related dissolution processes was carried out by Han et al. (2010; 2012), who determined that expansion processes in the well and near-well region exerted the largest effects on temperature during CO₂ injection. Although it has been found that the temperature change in the storage formation arising from Joule-Thomson cooling, CO₂ dissolution, and evaporation is relatively small, formation temperature in the near-well region may be significantly reduced by lower in-flow CO₂ temperature, which depends on the wellhead CO₂ temperature, heat loss and gain along the wellbore, and CO₂ enthalpy changes along the wellbore flow path (e.g., Jiang et al., 2014).

2.2.2. Plume Migration and Trapping

The SRCCS identified buoyancy as the main driving force for CO₂ plume migration in the two-phase region at distances far away from the well and in the long term. This driving force creates the iconic flared-funnel plume shape as CO₂ rises buoyantly and spreads laterally until trapped under large-scale caprock formations. Numerous analytical solutions to calculate plume shape and plume-front migration with increasing capabilities have been developed since 2005 (e.g., Nordbotten et al., 2005; Nordbotten and Celia, 2006; Dentz and Tartakovsky, 2009; Liu et al., 2010; Houseworth, 2012; and as summarized in Celia and Nordbotten, 2009). Capillary pressure effects on sharp-interface models were shown by Nordbotten and Dahle (2011) to affect CO₂ front migration, while capillary trapping was considered in the plume footprint solutions developed by Juanes et al. (2010) and in the gravity current models of Hesse et al. (2008). Recently, the ability has been developed to consider compressibility effects in the analytical solutions (Vilarrasa et al., 2013). Analytical solutions have also been developed for a one-dimensional radial CO₂-brine flow without accounting for the gravity effect (Noh et al., 2007; Burton et al., 2008; Mathias et al., 2011a; Mijic and LaForce, 2012; Azizi and Cinar, 2013; Mijic et al., 2014). These solutions are based on the fractional flow theory of Buckley and Leverett (1942) and can take into account all the near-well processes (dryout, salt precipitation, CO₂ dissolution and compressibility, and non-Darcy flow) when predicting the saturation profile, with the two sharp fronts separating the dry-out zone, the two-phase flow zone, and the single-phase brine flow zone. These solutions can be used for analyzing CO₂ injection into a thin storage formation or CO₂ migration in a single flow path. Key to fractional flow is the relative permeability of CO₂ and brine, which can take many forms, while capillary pressure is not considered. Vertical equilibrium models exploit the approximation that CO₂ and brine segregate by buoyancy and equilibrate relatively quickly in the vertical direction, meaning that the pressure field driving flow is effectively two dimensional in the horizontal direction (Gasda et al., 2009). By this approach, plume migration and even convective mixing can be modeled using hybrid analytical and numerical approaches, including reconstruction of vertical saturation profiles assuming hydrostatic equilibrium (Gasda et al., 2011; 2012).

Parallel with advances in analytical solutions to CO₂ plume migration and trapping, numerical simulation capabilities and applications also expanded rapidly since 2005. The expanded modeling capabilities include the development of simulators that can model all the phase combinations of CO₂ and brine, including transition between gaseous and liquid CO₂ and co-existing two-phase CO₂ that may occur during CO₂ injection or leakage (Pruess, 2011). At one end of the spectrum of numerical-simulation applications is the use of numerical simulation in confirming and testing analytical solutions, e.g., the study by Pruess and Nordbotten (2011) who simulated an idealized system involving buoyant CO₂ moving up a sloping caprock. At the other end of the spectrum are sophisticated state-of-the-art simulation studies utilizing high-resolution grids, considering heterogeneity, and applied in the spirit of uncertainty assessment for site-specific GCS demonstrations (e.g., Senel and Chuganov, 2012; 2013).

In between these end-member applications are a wide variety of applications aimed at answering questions about plume migration and trapping and related effects and processes. One illustrative example of important advances made since 2005 is related to Figure 5.9 in Section 5.2 of the SRCCS, which schematically showed the relative importance of trapping mechanisms versus time. Several simulation studies have attempted to confirm the basic trends shown in the figure and add quantitative numbers to the evolution of trapping. For example, Doughty (2010) simulated mass distribution over time of CO₂ in mobile, immobile, and dissolved fractions for a study of a potential GCS site in California, and found that the plume becomes stabilized ~20 years after injection stops as CO₂ becomes trapped as residual phase or dissolves into the native brine. A new trapping mechanism called “local capillary trapping” was identified through numerical simulation by Saadatpoor et al. (2010) as buoyant CO₂ becomes trapped below fine-grained lenses, into which it cannot permeate because of high capillary entry pressure. Another focus of research related to

residual-phase trapping is hysteresis in relative permeability. Juanes et al. (2006) pointed out the importance of hysteresis in immobilizing CO₂ by combined drainage-imbibition processes, while Doughty (2007) showed that hysteresis modeling produces an enhanced effect of residual-phase trapping and associated limitation to plume spread. Very recent research has elucidated further details of the pore-scale origins of relative permeability hysteresis, along with a practical description of hysteresis for reservoir-scale numerical simulation (Cihan et al., 2014).

Regarding concerns about relative permeability effects, exsolution of native gases (e.g., methane) from brine during CO₂ plume advance has been the subject of recent study. When native brine contains dissolved gas (e.g., methane), there is the possibility that gas exsolution in the brine will occur at the CO₂ plume front and interfere with CO₂ plume advance. These effects have been investigated by Oldenburg and Doughty (2011) and Oldenburg et al. (2013), who showed that CO₂ dissolution into native brine at the plume front will tend to produce a front of nearly pure methane, but that this front of exsolved gas is at low saturation and therefore exerts very little effect on brine displacement. The phenomenon of native gas exsolution has been recognized from fluid sampling data in the field and analyzed by modeling, as discussed by Doughty and Freifeld (2013) and Li and Li (2014).

Although injectivity and injection-related processes are a primary focus of attention for the design, permitting, and operational parts of GCS, research since 2005 has also focused on long-term CO₂ migration. At long times after injection stops, and/or at great distances from the injection well, pressure gradients due to injection become very small to absent, and the migration of CO₂ is mainly controlled by gravity (buoyancy) and capillary forces. Under these conditions, the standard multiphase version of Darcy's law can be simplified to a time-independent balance of gravity and capillary forces. This model equation can be used to simulate successive states of gravity-capillary equilibrium as CO₂ tends to rise but is at the same time excluded from pores having entry capillary pressure higher than the available gas-entry overpressure. This kind of modeling is called "invasion-percolation modeling," and has much lower computational demands than Darcy's law-based multiphase flow modeling, which has allowed researchers to model CO₂ migration of actual field demonstrations using highly refined grids that honor relatively fine-scale heterogeneity. The results of Singh et al. (2010), Cavanagh and Ringrose (2011), Cavanagh and Rostron (2013), and Cavanagh and Haszeldine (2014) are particularly notable for their CO₂ saturation distributions that are dominantly controlled by the topography of overlying caprock or low-permeability shale layers. Invasion-percolation models, however, neglect viscous forces, which means that pressure-driven flow cannot be accounted for. Some have also questioned the usefulness of high-resolution heterogeneity models, as details on small-scale heterogeneity and topography of storage formations are typically unknown. Research into model applicability and comparisons of invasion-percolation and Darcy's law approaches are the subject of ongoing studies.

2.3. Experience from Field Tests and Industrial Operations

As mentioned in Section 1, a number of pilot tests (e.g., a second injection phase at Frio in Texas, and projects at Ketzin, Germany and Otway, Australia), industrial-scale projects (e.g., the Snohvit Project in Norway), and large-scale demonstration projects (e.g., the Cranfield Phase III Project in Mississippi, the Illinois Basin Decatur Demonstration Project in Illinois, the Shenhua Ordos Project in China) have been added to the portfolio of field projects since 2005. These projects now represent a wide spectrum of storage formations (depth, thickness, permeability, porosity), operational conditions (injection rate, mass, time), and *in situ* formation conditions (pressure, temperature, and salinity) that are and will be useful for adding to the knowledge base of CCS pressurization, plume migration, and trapping (Hovorka, 2009; Würdemann et al., 2010; Underschultz et al., 2011; Finley, 2014; Hansen et al., 2013; Hovorka et al., 2013; Wu, 2014).

2.3.1. Near-Well Processes

Near-well processes have been monitored through bottomhole pressure and temperature measurements, geochemical sampling, geophysical and flow logging, and cross-well geophysical surveys (seismic and ERT) in several projects around the world (e.g., Freifeld et al., 2005; Daley et al., 2007; Muller et al., 2007; Lu et al., 2012; Butsch et al., 2013; Carrigan et al., 2013). Dedicated monitoring wells are often located between 30 and 300 m from injection wells, which allows for excellent observation of the near-well region. Observed CO₂ arrival times are often significantly shorter than the model-predicted values using homogeneous or layered rock properties. At early time of CO₂ breakthrough, a number of separate small flow paths of small CO₂ saturation have been observed at monitoring wells (e.g., Muller et al., 2007; Butsch et al., 2013). With time, the separate flow paths may merge into a few larger flow paths as their saturation increases. For example, the dynamic evolution of an individual flow path and merging of several small flow paths with time have been demonstrated in the Cranfield Phase III Project, on the basis of multiple repeat tracer tests and continuous cross-well geophysical imaging (Lu et al., 2012; Carrigan et al., 2013; Doetsch et al., 2013). Most studies have indicated that CO₂ migration is preferential along high-permeability channels and bypasses low-permeability lenses that act as capillary and permeability barriers (Carrigan et al., 2013). Indeed, preferential flow and bypassing may occur at very small contrast in permeability and entry capillary pressure because the viscosity of CO₂ is usually 10-20 times smaller than that of brine. Therefore, CO₂ migration in the near-well region is a combination of preferential flow caused by natural heterogeneity and viscous fingering caused by low-viscosity CO₂ displacing higher-viscosity brine. Salt precipitation and dryout has been attributed to the dramatic pressure increase observed in the early operation of the Snohvit project and was remediated to improve injectivity (Hansen et al., 2013).

2.3.2. Plume Migration and Trapping

Our understanding of large-scale CO₂ plume behavior comes mainly from time-lapse seismic surveys and measurement of CO₂ arrival times at monitoring wells. Here, we focus on what we have learned through these types of monitoring on a site-specific basis. Example sites discussed below include the successful time-lapse seismic surveys at Ketzin for imaging the evolution of CO₂ plume in the shallow Stuttgart Formation, the successful time-lapse seismic surveys at Sleipner for imaging the CO₂ plume in a thick storage formation affected by multiple continuous/discontinuous mudstone layers, and the well-based monitoring of arrival times at kilometer scale at In Salah. For each selected site, we give a brief description of the storage site characteristics and the operation of CO₂ injection, followed by a discussion of the observed migration and trapping behavior.

At Ketzin, a total of 67,271 tonnes of CO₂ were injected from June 2008 to August 2013 through an injection well perforated between a depth of 630 and 650 m (Würdemann et al., 2010; Martens et al., 2012). The injection zone is the top 18 m thick high-permeability portion of the Stuttgart Formation. Detailed site characterization showed that the upper injection zone is highly heterogeneous in lithology, consisting of permeable sandstone channels embedded within flood-plain siltstones and mudstones of low permeability (Förster et al., 2010; Norden et al., 2010). Injected CO₂ arrived after 21 days of injection at a monitoring well about 50 m away from the injection well, whereas arrival at another monitoring well about 112 m away was much delayed (271 days), demonstrating the effect of tortuous higher-permeability flow channels (Kempka and Kuhn, 2013).

To monitor the evolving plume behavior at Ketzin, two repeat surveys were conducted in 2009 and 2012 after injection of 22,000 and 61,000 tonnes of CO₂, respectively (Ivanova et al., 2012; 2013). Comparison with a baseline survey prior to injection (Juhlin et al., 2007) clearly shows that the evolving plume is not radially symmetric and has a pronounced westward migration tendency while the reservoir up-dips northward (see Figure 2.2). The highly irregular responses can be attributed to the heterogeneity and channeling in the reservoir. The CO₂ plume increases in lateral extent from

300 m - 400 m (with a thickness of about 5 to 20 m) in 2009 to 400 m - 600 m (with stronger anomaly) in 2012. The plume-averaged CO₂ saturation in 2009 is on the order of 0.15 when calculated using average porosity, injection zone thickness, plume area, and CO₂ density (Ivanova et al., 2012). This relatively small plume-averaged saturation may be caused by preferential flow in the horizontal direction and by the significant gravity effect between CO₂ at a density of 266.6 kg/m³ and brine at a density of 1,157.0 kg/m³.

Figure 2.2. Maps of normalized amplitude difference between repeat seismic surveys (2009 on the left; 2012 on the right) and the baseline survey, showing the lateral extent of CO₂ plume at Ketzin, Germany (from Ivandic et al., 2013). The three gray circle symbols depict the injection well (left) and two monitoring wells (right). The term “amplitude difference” refers to the strength of the reflected seismic wave.

In the Sleipner Project, CO₂ separated from produced natural gas has been injected through a deviated well from an offshore platform into the reservoir at a depth of 800 to 1100 m below sea level. The injection point is located at a depth of 1012 m below sea level. The average injection rate is 0.84 Mt/year starting in 1996, with a total of 15 Mt CO₂ injected by the end of 2014 (Skalmaraas, 2014). The reservoir mainly contains unconsolidated sandstones (Utsira Sand) of high permeability (1 to 3 Darcy) and high porosity (0.35–0.4), with eight thin mudstone layers (continuous and discontinuous) between the injection point and the base of the caprock (Chadwick et al., 2004). These mudstone layers have been identified in well logs, but their lateral continuity and discontinuity are only evidenced from enhanced contrasts in eight repeated seismic surveys in 1999, 2001, 2002, 2004, 2006, 2008, 2010, and 2013, in comparison with the baseline survey in 1994. Of particular interest are the buoyancy-driven migration patterns of CO₂ within the storage formation, which are strongly affected by the reservoir structures. Today's understanding of the CO₂ migration behavior at Sleipner is as follows (Arts et al., 2008; Boait et al., 2012). The CO₂ plume initially spreads laterally under each mudstone layers, breaks through, migrates further up, and encounters another mudstone horizon. This sequence repeats itself until the CO₂ finally accumulates under the caprock and then follows the topography of the caprock base, mainly driven by gravity (see Figure 2.3). Pressure effects due to injection are believed to be negligible because of the very high permeability and large thickness of the storage formation (Chadwick et al., 2012).

Figure 2.3. Maps of the amplitude difference between repeat seismic surveys and the 1994 baseline survey for the uppermost CO₂-filled horizon at Sleipner, Norway (from Skalmernaas, 2014).

In the In Salah Project, three 1.5 km long horizontal wells were used to inject 4.3 Mt CO₂ separated from produced natural gas from the Krechba field into the water leg of the gas reservoir between 2004 and 2011. The reservoir is of an average matrix permeability of 10 md and a porosity of 0.15 at a depth of 1890 m, overlain by a 900 m thick caprock. CO₂ injection began in August 2004 at two injection wells (KB-501 and KB-503) and in April 2005 at KB-502. Owing to some concerns about caprock fracturing, the injection was stopped in June 2011 and has not been restarted. One very interesting finding is the surface uplift induced by CO₂ injection and imaged by interferometric synthetic aperture radar (InSAR) technology (Vasco et al., 2008a, b, 2010; Rucci et al., 2013). InSAR is an often satellite-based radar technique used in geodesy and remote sensing to generate maps (interferograms) of surface deformation, using differences in the phase of the wave returning to the satellite (e.g., Massonnet and Feigl, 1998; Burgmann et al., 2000). The InSAR images at In Salah exhibit transient uplift patterns with elliptic-shaped pressure plumes, showing anisotropy of permeability.

Well inspection was conducted routinely at several existing appraisal wells and five gas-producing wells, which are located several kilometers to tens of kilometers from the three injection wells. A CO₂ leak was found at a small rate at the wellhead of KB-5 (a suspended appraisal well) in June 2007, indicating that CO₂ breakthrough to this well occurred between August 2006 and June 2007 (between the time of two wellhead inspections). Injected CO₂ at the three injection wells was tagged with different perfluorocarbon tracers (PFTs) in June 2007 and it was found that it took 10 months for the PFT released at KB-502 to arrive at KB-5 (Ringrose et al., 2009; Mathieson et al., 2010). Both CO₂ breakthrough and tracer arrival time indicated that CO₂ travels very quickly over a 1.3 km distance between the two wells. In addition, PFT-tagged injected CO₂ at KB-502 was detected at KB-14, a gas producer, in July 2012, indicating that injected CO₂ migrated over a 3.5 km distance from KB-502 to KB-14 over four years, even though the total injected CO₂ mass was only 1.2 Mt (Bissell, 2012). The arrival times over a several-kilometer scale suggest that injected CO₂ may migrate through existing open or new fractures, the latter created when the injection pressure was occasionally higher than the fracturing pressure (Iding and Ringrose, 2010).

2.3.3. Site-Specific Numerical Simulations via Inverse Modeling

While the monitoring data obtained in recent field studies have provided valuable information on CO₂ migration patterns, interpretation and prediction of these processes with numerical models continues to be challenging, because of the inherent uncertainty of geologic systems and the types of (often sparse and potentially noisy) observation data. Site characterization may provide reasonable estimates of the range of rock properties, but often little information on their spatial distribution and small-scale heterogeneity. Field monitoring data can help improve our understanding of the spatial variability and distribution of rock properties, but the data are always limited, and the spatial distribution of rock properties may never be completely understood. To date, history matching of observation data from CO₂ field projects has mostly been done with simple trial-and-error methods (e.g., Doughty et al., 2008; Hosseini et al., 2013; Kempka and Kuhn, 2013; Senel et al., 2014). (This type of approach is routinely applied in hydrocarbon production.) Such methods are effective when calibrating a limited number of parameters, for example the single-value permeability of the shale layer at the Illinois Basin Decatur Project site (Senel et al., 2014), but cannot deal with many unknowns or large numbers of monitoring data. New approaches for inverse modeling have been recently proposed in the field of CO₂ storage (e.g., Oladyshkin et al., 2013; Tavakoli et al., 2013). For example, an efficient surrogate response surface global optimization algorithm “Stochastic RBF” (stochastic radial basis function) was used to calibrate the model parameters in a semi-synthetic case (Espinete et al., 2013). An adaptive sparse grid surrogate method was used for robust optimization of CO₂ sequestration strategies under geological uncertainty (Petvipusit, et al., 2014). Most recently, two methods of Kalman Filter have been developed for real-time control of CO₂ storage projects (Kitanidis, 2014; Kitanidis and Lee, 2014): the Compressed State Kalman Filter (CSKF), and the Spectral Kalman Filter (SpecKF). These methods have been tested using synthetic data of pressure, temperature, and CO₂ saturation acquired at wells for a hypothetical storage case (Kokkinaki et al., 2014). The testing results have demonstrated the efficiency of these developed extended KF methods when dealing with large numbers of unknown permeability values. More applications to real sites will be needed.

3. Pressure Buildup and Brine Displacement

In contrast to CO₂ sequestration in depleted oil and gas fields, which are often underpressured from decades of hydrocarbon production, storage of CO₂ in deep saline aquifers will mostly occur at natural formation pressure. When CO₂ is injected into such formations, it needs to be forced from the injection wells into water-saturated pores at pressure higher than the natural formation pressures to be able to displace resident brines. If reservoir permeabilities are low to moderate, the downhole injection overpressures required to introduce a given amount of CO₂ per unit time can be quite high near the injection wells, and care needs to be taken not to cause geomechanical damage in the reservoirs and the confining units. Regulatory agencies generally limit the maximum downhole pressure in injection wells to avoid opening existing fractures or creating new fractures. This maximum pressure is generally based on the *in situ* formation stresses and other geomechanical properties. In deep reservoirs with natural heterogeneity and low-to-moderate permeability, having sufficient injectivity can be a key challenge for cost-effective sequestration, because injecting the target amount of CO₂ may require multiple injection wells, long-reach horizontal wells, or other novel solutions. The In Salah Project in Algeria is one prominent example of a low-permeability storage reservoir where operators aimed to achieve sufficient injectivity by using three long-reach horizontal wells for CO₂ injection (Ringrose et al., 2009; Mathieson et al., 2010; Wright et al., 2010).

Whereas injectivity is primarily related to local pressure and brine displacement in the vicinity of injection wells, researchers have become increasingly aware of the potential pressure effects away from the injection locations (Figure 3.1). In particular for large industrial-scale projects, pressure signals can propagate far beyond the CO₂ plume, on the scale of tens to even hundreds of

kilometers. Concerns about large-scale pressure buildup and brine migration caused by industrial-scale CO₂ sequestration have been mentioned as early as in the 1990s (van der Meer, 1992; Bergman and Winter, 1995; Gunter et al., 1996), but quantitative assessments of the magnitude and implications of regional reservoir pressure buildup had not been conducted at the time of writing the SRCCS. This changed in the mid-to-late 2000s, and today there is a great deal of research on various aspects of injection-driven pressure evolution in deep saline aquifers, reviewed and discussed in the subsections below. Initial studies were based on modeling assessment of hypothetical CO₂ storage scenarios (e.g., Zhou et al., 2008; Birkholzer et al., 2009), both for idealized subsurface conditions and for actual reservoirs or basins, to analyze pressure effects as a function of space and time, including the effects of confinement (Section 3.1). These initial studies highlighted the need for evaluating the possibility of unwanted effects from large-scale pressure and brine displacement, such as pressure-driven leakage into protected groundwater or other subsurface resources (Section 3.1) and possible geomechanical damage, including the potential for slip along critically stressed faults (Section 3.2). Such effects can become a concern even if the large-scale pressure changes are much smaller than the pressure thresholds typically employed to ensure that local injection pressures do not cause geomechanical damage in the reservoir and the confining units.

Since publication of the SRCCS, researchers also began to realize that pressure effects would need to be accounted for when estimating CO₂ storage capacity. The issue of pressure behavior during CO₂ injection and its connection with storage capacity is briefly introduced in Section 3.3. For further reading on this subject, we point to another paper in this Special Issue (Bachu, this issue). Other post-SRCCS topics addressed below include pressure-management strategies for cases where storage capacity is limited by pressure buildup (Section 3.4) and use of pressure signals or pressure-induced geomechanical effects for advanced monitoring (Section 3.5).

Figure 3.1. Schematic showing different regions of influence related to CO₂ storage in a saline reservoir (from Birkholzer et al., 2009). The large footprint of elevated pressure could displace brines within the storage reservoir or could cause upward brine migration through caprock imperfections or along high-permeability conduits such as faults and abandoned boreholes.

3.1. Factors Affecting Pressure Buildup and Brine Migration in Large-Scale CCS Projects

To understand basic characteristics of large-scale pressure buildup and brine migration, Zhou et al. (2008) and Birkholzer et al. (2009) conducted simulation studies of industrial-scale CO₂ storage (i.e., at injection rates of several million tonnes per year) in simplified subsurface reservoirs idealized as "closed" and "open" systems, respectively (Figure 3.2). According to Zhou et al. (2008), closed (or compartmentalized) systems may be formed by bounding faults, by reservoirs pinching out, or by reservoir heterogeneity. When large volumes of CO₂ are injected into a compartmentalized formation acting as a closed system, a significant pressure buildup can be produced because the displaced brines cannot migrate beyond the reservoir boundaries. In this case, the storage capacity mainly depends on pore and brine compressibilities that provide expanded pore space available for storing the injected CO₂, and on the maximum pressure buildup that the formation rocks can tolerate without jeopardizing the geomechanical integrity of the caprock or triggering other unwanted effects (Zhou et al., 2008; Mathias et al., 2011b).

Open systems, on the other hand, are defined as formations from which the native fluid can escape laterally and make room for the injected CO₂ (Figure 3.2, top). These may be formed, for example, by regionally extensive reservoirs that are much larger than the expected pressure perturbation from CO₂ injection. Birkholzer et al. (2009) modeled CO₂ migration and pressure response in an idealized open subsurface system comprising a series of laterally extensive aquifers and aquitards that extend from the deep saline storage formation to shallow freshwater aquifers. Based on a series of sensitivity cases, the authors concluded that reservoir pressurization above fracturing pressure is less of a concern for such systems compared to closed systems, except close to the injection well(s). However, pressure signals can propagate very far within the storage formation, which may have several other indirect storage-capacity implications, as discussed later in this section.

Figure 3.2. Schematic showing open versus closed storage formations (from Zhou et al., 2008).

One important finding from these early generic studies of reservoir pressurization is that proper definition of model boundary conditions is paramount, not just in the lateral direction but also in terms of vertical interlayer communication. In both cases of closed and open systems, the characteristics of pressure buildup and brine migration are strongly affected by the properties of the overlying and underlying confining units (IEAGHG, 2010). Seals that are suitable for long-term

trapping of CO₂ allow for slow interlayer migration of brine, which over the often very large areas affected by pressure perturbation can result in considerable transfer of brine from the storage formation vertically upward and/or downward. Modeling results in Zhou et al. (2008) and Birkholzer et al. (2009) suggest that this interlayer pressure communication, sometimes referred to as diffuse leakage or pressure bleed-off, becomes important when the regional-scale vertical permeability of confining units is about 0.1 microdarcy or higher. A review by IEAGHG (2010) suggests that regional permeabilities of common shales are likely in the microdarcy range for a storage-depth window between one and three kilometers.

Figure 3.3 shows a typical example of a volumetric brine balance in response to large-scale injection of CO₂ into a deep saline aquifer with diffuse leakage of brine, for a hypothetical future scenario with multiple industrial-scale storage sites in the Illinois Basin (Birkholzer and Zhou, 2009). The total volume of displaced brine, equal to the total volume of injected CO₂ excluding dissolved CO₂, is accommodated partially by the compressibility-related pore-volume increase in response to pressure buildup and partially by the cumulative brine volume released through the lateral and vertical boundaries, the latter allowed by a shale formation with a 1 microdarcy permeability. Compressibility effects dominate during the injection phase and the early post-injection phase. Later, as the system slowly progresses towards quasi-equilibrium, compressibility effects become less relevant, while more and more fluids egress from the model domain. At 50 years (the end of the injection period), the cumulative volume of brine released through the boundaries accounts for 9% of the total displaced brine volume. At 200 years, it accounts for 86%, the majority of which is from vertical interlayer communication.

Figure 3.3. Evolution of volumetric brine balance for the Illinois Basin model (from Birkholzer and Zhou, 2009). The top black line shows the cumulative volume of displaced brine, which is equal to the total volume of free-phase CO₂.

In compartmentalized storage formations (closed systems), diffuse leakage of brine through confining layers was found to have a considerable effect in reducing overall pressure buildup, thus allowing for significantly higher storage capacity than would be estimated when assuming impermeable confining units. In an end-member case with relatively large seal permeability of 10 microdarcy, the average formation pressure calculated by Zhou et al. (2008) eventually reached an asymptotic maximum despite continued injection. Because of the widespread pressure buildup, the volumetric flow rate of displaced brine through the confining units becomes so large that it

eventually equals the volumetric rate of injected CO₂. In open systems, interlayer communication has a considerable impact on the lateral extent of pressure perturbation. Figure 3.4 shows results from a simulation study for industrial-scale CO₂ injection into a deep brine formation with an overlying sequence of permeable reservoirs and interbedded sealing units (Birkholzer et al., 2009). Four idealized simulation cases are shown with different vertical permeability of the seals (ranging from 0.01 to 10 microdarcy). It can be clearly seen that the lateral extent of the pressure perturbation is very large, on the order of tens of kilometers (which compares to a CO₂ plume extent of about 2 kilometers). It is also evident that the brine leakage from interlayer communication with relatively permeable sealing units has a positive attenuation effect on the pressure conditions *within* the storage formation, reducing the lateral propagation while allowing for pressure diffusion in the *vertical* direction. The relative importance of diffuse leakage was later confirmed by local and global sensitivity analyses (e.g., Birkholzer et al., 2010; Wainwright et al., 2013), where the relative sensitivity of distant pressure and brine migration to seal permeability was shown to be of similar importance to the sensitivity to storage formation properties such as permeability, compressibility, and porosity (Schaefer et al., 2012).

Figure 3.4. Contours of pressure buildup for idealized radially symmetric multilayer sequence of permeable reservoirs and seals, at 30 years of CO₂ injection for different values of seal permeability k_s (from Birkholzer et al., 2009). CO₂ injection occurs into the lower-most reservoir in the center of the radially symmetric domain. A cutoff value of 0.1 bar is set for the contours. The lateral extent of the CO₂ plume, not shown in this figure, is about 2,000 m from the injection well.

Considering the large areas of hydrologic perturbation that will result from wide deployment of industrial-scale CO₂ storage, researchers looked into the potential environmental consequences, in particular, impacts on groundwater resources (e.g., Nicot, 2008; Birkholzer et al., 2009). A consensus finding was that lateral and vertical pressure propagation and brine migration are generally not a concern for shallower hydrologic systems if the sealing units remain competent over the large areas affected by pressure perturbation. In contrast, brine leakage can potentially lead to groundwater contamination through localized pathways (e.g., leaky wellbores, faults, areas with less competent seals), as the pressure buildup in the storage reservoir provides a driving force for upward migration of brine. Brines not only have elevated-to-high salinity, but may also contain high concentrations of heavy metals, natural radioactive materials, and other major ions. The potential for and the mechanisms of leakage via such permeable conduits have been studied extensively over the past decade, mostly with regards to CO₂ escaping from storage, but in several studies also with a

particular focus on brine leakage (e.g., Celia et al., 2011; Birkholzer et al., 2011; Walter et al., 2012; Nicot et al., 2013; Walter et al., 2013; Tillner et al., 2013) Brine leakage is also a central element of some regulatory approaches for CO₂ storage projects. For example, the geologic sequestration regulation in the United States requires definition of a so-called Area of Review (AoR), which encompasses the region overlying the extent of fluid-pressure increase sufficient to drive formation fluids into an overlying freshwater aquifer (EPA, 2010, 2013). Within the AoR, owners or operators of CO₂ injection wells are required to identify any potential conduits for fluid movement, assess the integrity of any artificial penetrations (e.g., abandoned wells), conduct performance monitoring, and perform corrective action where necessary. For industrial-scale projects, the AoR sizes delineated based on pressure considerations can be very large, meaning the regulatory requirements regarding site characterization and performance monitoring can become quite burdensome (Birkholzer et al., 2014). Further complications arise with AoR definition when the injection zone is initially overpressured relative to overlying freshwater aquifers (e.g., Oldenburg et al., 2014).

Following the initial modeling work by Zhou et al. (2008) and Birkholzer et al. (2009), which assumed highly idealized subsurface conditions, several site-specific simulation studies investigated regional-scale pressure and brine-migration behavior in response to CO₂ storage. These studies represented the actual conditions in hydrogeological basins, for hypothetical CO₂ storage scenarios consistent with the assumption that many large projects will be required in the future to make meaningful contributions to global climate change mitigation. Examples include industrial-scale CO₂ sequestration in deep saline reservoirs in the Texas Gulf Coast Basin in the United States (Nicot, 2008), in the Tokyo Bay in Japan (Yamamoto et al., 2009), in the Illinois Basin in the United States (Birkholzer and Zhou, 2009; Zhou et al., 2010; Person et al., 2010; Bandilla et al., 2012; Mehnert et al., 2014), in the Southern San Joaquin Basin in the United States (Zhou and Birkholzer, 2011), in the North German Basin (Schaefer et al., 2012; Tillner et al., 2013), and in the Basal Aquifer of the Prairie Region in Canada and the Northern Plains region in the United States (Huang et al., 2014).

In general, the main conclusions derived from the earlier idealized models (Zhou et al., 2008; Birkholzer et al., 2009) were confirmed in the site-specific simulations. One additional topic emerged in some of the regional-scale studies, namely the potential impact of having multiple storage sites operating in the same formation. Birkholzer and Zhou (2009), for example, predicted the regional-scale hydrogeological changes in response to simultaneous CO₂ storage at 20 individual storage sites spaced about 30 km apart in the center of the Illinois Basin (Figure 3.5a). Together, injection at these sites amounts to 100 Mt CO₂, representative of a hypothetical scenario in which about one third of the current annual emissions from large stationary sources in the basin are captured and stored. The pressure results for this scenario, shown in Figures 3.5b and 3.5c at the end of the injection period (50 years), exhibit a continuous region with considerable pressure increase in the basin center, indicating superposition of individual pressure responses and strong pressure interference between different projects. In contrast, the maximum size of the CO₂ plumes is about 6–8 km in diameter, much smaller than the spacing between different injection sites. With respect to the far-field impacts of CO₂ injection and storage, pressure changes propagate very far, as much as 150 to 200 km beyond the basin center (Zhou et al., 2010). As observed before, pressure bleed-off can be a relevant attenuation factor, as seen in the comparison between a microdarcy seal-permeability case (Figure 3.5b) and a 0.01 microdarcy seal-permeability case (Figure 3.5c).

Note that the Illinois Basin was also the target of another multisite CO₂ sequestration study conducted by Person et al. (2010). In this study, the total amount of CO₂ stored in the Mount Simon formation is about the same as in Birkholzer and Zhou (2009) and Zhou et al., (2010), but the pressure footprint of individual storage projects is smaller, and less pressure interference is observed. At the same time, the maximum injection pressures observed in Person et al. (2010) are much higher. While the two modeling studies differ in several ways—such as the distribution of

injection wells, the selection of hydrogeologic properties and boundary conditions, and the dimensionality of the simulations—the main reasons for the discrepancies in pressure behavior are the much lower formation permeability and higher formation compressibility assumed in Person et al. (2010). Whereas Birkholzer and Zhou (2009) and Zhou et al. (2010) derived basin-scale permeability values using a few available deep well logs from the center of the basin and from natural gas storage projects, Person et al. (2010) extrapolated a regional depth-porosity-permeability relationship established for the extent of the Mount Simon formation outside of the Illinois Basin. In both cases, scarcity of data typical for deep saline reservoirs without a history oil and gas development leads to considerable model uncertainty. Birkholzer and Zhou (2009) discussed the challenge of obtaining sufficiently detailed and realistic hydrogeologic properties for large subsurface volumes, which severely limits our ability to place meaningful and reliable limits on quantities and pathways for pressure buildup and brine migration. They point out that a change in lateral permeability by one order of magnitude, arguably a reasonable uncertainty range for large-scale hydraulic properties, would translate into a change in pressure propagation distance by roughly a factor of three, a considerable difference in terms of area affected by pressure buildup. Considering the importance of large-scale predictions of hydrogeologic impacts in response to CO₂ storage, Birkholzer and Zhou (2009) recognized the usefulness of large field demonstrations with far-field measurements of brine pressurization for better understanding the relevant processes and parameters and reducing prediction uncertainty.

Figure 3.5. (a) Site map of the Illinois Basin, including the thickness (m) of the Mount Simon Sandstone (in flooded contour), basin boundary (gray polygons), major faults (thick black lines), state borders (thin gray lines), model boundary (thick red line), the center injection area (pink polygon), and 20 storage sites (black squares). Simulated pressure buildup (MPa) at 50 years of injection with diffuse leakage through caprock of a vertical permeability of (b) one microdarcy and (c) 0.01 microdarcy. The cut-off pressure buildup is 0.01 MPa. Figure is taken from Zhou and Birkholzer (2011).

Birkholzer and Zhou (2009) also raised the question whether and/or how regional impacts of geologic sequestration with multiple storage sites in a given basin can be effectively regulated, in particular in consideration of potential pressure interference. The EU directive on geological storage of CO₂ (EU Directive, 2009) requires that CO₂ storage operations must be managed in such a way that they will not impact other storage sites. A less restrictive (and probably more realistic) possibility could be to regulate under a “first come, first serve” principle, where early applicants in a basin would have the advantage of delineating their AoR without consideration of other possible storage operations, and later applicants would have to develop their permitting case under consideration of the pressure impacts of all ongoing or approved operations in the region. An alternative, more coordinated approach would be a two-tier permitting level, as initially suggested by Nicot and Duncan (2008). These authors suggest two permitting levels: The first level (referred to

as general permit) would involve an overarching federal or state agency to develop regional assessments of large brine reservoirs, with the goal of characterizing them to the point that they are “sequestration ready.” The second level would involve permit applications for individual sites, with the expectation that the burden faced by an applicant would be less because regional assessments have already been conducted, and the permitting process for each site would be reviewed under the umbrella of a coordinated regional permit.

3.2. Geomechanical Damage and Induced Seismicity

The importance of geomechanical processes induced by local- and regional-scale pressure increases during large-scale geologic carbon sequestration operations—including the potential for faults reactivation—has become widely recognized since publication of the SRCCS in 2005. A state-of-the-art review of the basic geomechanical processes and modeling approaches associated with CCS is given in Rutqvist (2012), with focus on storage in deep sedimentary formations, in particular saline aquifers. Figure 3.6 (bottom left) illustrates that any change (even small) in reservoir pressure (and temperature) will induce some stress-and-strain changes in and around the injection zone. Such changes are not generally a concern; in fact, they can be useful because they generate detectable signals for monitoring subsurface flow, such as small but measurable ground surface deformations or micro-seismic events that can be observed by geophones (Section 3.5). However, if reservoir pressure becomes very high, more substantial changes may occur, including the potential for irreversible geomechanical damage, e.g., creating new fractures, straining the well assembly, or reactivating faults (Figure 3.6, bottom right).

Figure 3.6. Geomechanical processes and key technical issues associated with CCS in deep sedimentary formations (from Rutqvist, 2012). Top: the different regions of influence for CO₂ plume, reservoir pressure changes, and geomechanical changes in a multilayered system with minor and major faults. Bottom left: injection-induced stress, strain, deformations and potential microseismic events. Bottom right: potential geomechanical damage processes.

The topic of induced seismicity has been hotly debated in recent years, not just with focus on CO₂ sequestration but also with regard to other subsurface activities involving injection of large volumes of fluids (NAS, 2012). Concerns about induced seismicity are related to the potential for triggering notable (felt) or even damaging seismic events and how this could impact the public perception of geological carbon sequestration. Zoback and Gorelick (2012) also pointed to the long-term integrity of a CO₂ repository, because slip on existing, perhaps unidentified faults can lead to permeability enhancement, seal breaching, and eventually leakage of CO₂. As discussed in NAS (2012), the risk of induced seismicity from CCS is currently difficult to assess accurately. To date, no harmful induced seismicity has been associated with any of the current CCS demonstration or industrial projects (in contrast to other subsurface energy production activities), as reviewed by Verdon et al. (2013) on the Sleipner, Weyburn, and In Salah projects. However, the volumes of CO₂ injected at these sites so far are small in comparison to the volumes being considered for future CCS projects (NAS, 2012).

In contrast to 2005, when the SRCCS was published, there is now a growing body of research related to developing hydromechanical modeling approaches for predicting pressure-induced fault slip and its potential impacts (e.g., Rutqvist, 2012; Cappa and Rutqvist, 2012; Rinaldi et al., 2014). Scientists are also working on quantitative hazard and risk assessment with regards to induced seismicity and the potential for damage, both in terms of felt seismic events and the possibility of creating leakage pathways (e.g., NRAP, 2013), and have developed best-practice guidelines to evaluate and manage the potential for induced seismicity (e.g., Majer et al., 2012). So-called “traffic light” approaches have been proposed for responding to instances of induced seismicity. Such approaches rely on detailed local monitoring to be able to react promptly when seismic events of increasing intensity are recorded. Zoback (2012) provided a summary of a traffic light system for the purpose of managing potential induced seismicity from wastewater disposal. Bachmann et al. (2009) proposed a forecasting tool based on statistical aftershock sequence models and tested them against the observed seismic sequence induced by injection at the enhanced geothermal site in Basel, Switzerland. Such a model could be used in real time to guide management and mitigation of seismic risks as they evolve (IEAGHG, 2013b). Today, the majority of large CCS demonstrations or industrial-scale projects employ local seismic networks to monitor for any detectable signals; meanwhile, the topic of predicting, managing, and mitigating induced seismicity remains a field of active research.

3.3. Pressure-Related Capacity Constraints

With studies of large-scale pressure impacts from CCS projects came an understanding that regional reservoir pressurization can be a limiting factor for sequestration capacity in saline aquifers (Kaldi and Bachu, 2010; Zhou and Birkholzer, 2011; Thibeau et al., 2014), because the possibility of distant pressure-related impacts needs to be considered. We already discussed (in Section 3.1) the potential environmental concerns regarding groundwater contamination stemming from pressure-driven brine leakage through conductive pathways, such as improperly plugged abandoned wells or distant faults, and we mentioned in Section 3.2 the potential for fault reactivation and possibly seal breaching. Large-scale pressurization can also be an issue for activities involving exploitation of subsurface resources in the area such as oil and gas or geothermal energy (IEAGHG, 2013a), or may affect neighboring CO₂ storage sites that reside in the same formation. Finally, large areas with pressure increases can lead to more complex and costly permitting, higher effort for site characterization, and more expensive monitoring. As a result of such concerns, pressure constraints may need to be imposed at distant locations that are more stringent than the local injection pressure thresholds, which are often quite large. It was postulated that such pressure constraints in regions far away from the injection wells could significantly affect the realistic storage capacity of a basin or an aquifer (Birkholzer and Zhou, 2009; Thibeau et al., 2014). Estimates of CO₂ storage capacity that account for pressure impact will typically be based simulations of CO₂ injection, both analytical and numerical, and are often referred to as “dynamic” because they involve the time

element. "Dynamic" storage capacity contrasts with the "volumetric" storage capacity, which is simply based on aquifer volume occupied by CO₂. We refer to a companion paper in this Special Issue for a review of "volumetric" and dynamic storage capacity estimates (Bachu, this issue).

We should mention that pressure concerns related to large-scale sequestration projects can be managed by strategically extracting brines from the CO₂ storage reservoirs, as discussed in the next section of this paper. Such methods, while adding cost, can provide many benefits such as increased storage capacity, reduced failure risk, simplified permitting, smaller area of review for site characterization, smaller area for monitoring, and, possibly, manipulation of the CO₂ plume (Buscheck et al., 2012).

3.4. Pressure Management

Concerns about local- or regional-scale pressurization have motivated research on engineering approaches for subsurface pressure control, usually involving some strategy of extracting native brines from the storage reservoirs while CO₂ is injected. The produced brines would be transferred to the surface, and either treated and used, disposed of, or re-injected elsewhere (Court et al., 2011; Bergmo et al., 2011). In recent years, pressure management approaches via brine extraction have been studied in generic modeling exercises demonstrating proof of concept and feasibility, but so far brine extraction has not been utilized in actual GCS projects, mainly because the currently limited CO₂ storage volumes did not result in large-scale pressure increases. However, for the large-scale projects expected in a future CCS large-scale-deployment scenario, brine-extraction schemes are found to be beneficial in theory, allowing for higher storage capacity and improved injectivity (Buscheck et al., 2012) and reducing the risk of environmental impacts and induced seismicity (Birkholzer et al., 2012). The Gorgon Project in Australia will involve the possibility of brine extraction through four water production wells located to the west of the site (Flett et al., 2008; Liu et al., 2013). Dempsey et al. (2014) recently went a step further and introduced the idea of "passive" injection. In this concept, brine extraction wells create negative pressure relative to initial reservoir conditions, which can then be used to pull CO₂ "passively" out of nearby injection wells. In terms of extraction ratio (mass of brine extracted relative to mass of CO₂ injected), this method is not as efficient as others: the long-term mass production of brine would be approximately 1.7 times that of CO₂ sequestered. This compares to studies by Buscheck et al. (2012), where the net extracted volume of brine is equal to the injected CO₂ volume (which is equivalent to a mass-based extraction ratio of about 1.3).

Some researchers suggest that brine extraction could create some economic value via beneficial use of treated brine (e.g., Bourcier et al., 2011; Maulbetsch and DiFillipo, 2010; Breunig et al., 2013) or may reduce other costs for CO₂ storage, such as those related to compression, liability insurance, site characterization, or monitoring (Buscheck et al., 2012). Many others are concerned, however, that pressure management for large projects would require handling very large volumes of brackish or saline water, all of which can be technically challenging and expensive. Harto and Veil (2011) and Harto et al. (2011) evaluated the cost of extracted water management based on analogs from water production in oil and gas operations. While their estimates vary widely depending on location (e.g., transportation distance, discharge options), brine characteristics (e.g., TDS, contaminants), and selected water management options (e.g., disposal of brines, beneficial use such as desalination for drinking water production), the authors conclude that the cost of dealing with large volumes of extracted water can become a significant factor in the economic viability of GCS projects.

Recognizing the cost of extracted water management, recent work by Birkholzer et al. (2012) and Cihan et al. (2015) is aimed at developing optimization methods for pressure control, with the goal of minimizing the volume of extracted brine while maximizing CO₂ storage and meeting other constraints needed for safe and efficient GCS operations. For given pressure constraints, such as the

maximum pore pressure along a critically stressed fault, the optimization algorithm will find optimal solutions for extraction well placement and transient pumping rates. Example applications to hypothetical CO₂ storage scenarios demonstrate that strategic extraction can achieve a significant reduction in the total brine extraction volumes (with extraction ratios ranging from about 20% to 70% depending on the conditions) while limiting pressure increases where and when necessary (Cihan et al., 2015).

Another approach for pressure management involves surface dissolution of CO₂ into brine extracted from the storage formation and reinjection of the CO₂-saturated brine into the storage formation (Burton and Bryant, 2009; Jain and Bryant, 2011). This “surface dissolution” strategy eliminates the risk of buoyant migration of stored CO₂. It also limits the extent of pressure elevation during injection and nearly eliminates the displacement of brine, because the mass of CO₂-saturated brine to be injected exceeds the mass of extracted brine by only a few percent. The economics of this approach depend critically on solubility of CO₂ in brine, which is a function of pressure, temperature, and salinity. Using a CO₂ solubility of 0.021 (mole fraction) in brine as in Jain and Bryant (2011), representative of brine with 75,000 ppm salinity at 27°C initial temperature and 9 MPa initial pressure, the mass of brine to be extracted and reinjected is about 17 times larger than the mass of CO₂ that needs to be injected. Burton and Bryant (2009) and Jain and Bryant (2011) discuss the extremely large brine circulation volumes as a major disadvantage of the surface dissolution approach, but point out that the power requirement for pumping and mixing should be manageable. To date, there are no CO₂ storage projects using the surface dissolution method for pressure management.

3.5. CCS Monitoring Using Pressure and Surface Uplift

Since publication of the SRCCS in 2005, advanced monitoring techniques for CCS projects have increasingly relied on measuring pressure signals and in some cases also pressure-induced deformations. As an example for the use of pressure signals, one recently proposed strategy for detection of leakage pathways and seal breaching is to monitor pressure anomalies in overlying reservoirs (also referred to as “above-zone” monitoring). Because pressure signals propagate fast and far in the subsurface, above-zone monitoring can under certain conditions allow for “early” detection of pathways, ideally early enough such that preventive and correction measures can be taken before harm is done (Jung et al., 2013). A great deal of research has been conducted to evaluate the feasibility of such above-zone pressure monitoring, mainly via numerical modeling of simplified storage systems. Detectability studies and sensitivity analyses have been performed for a broad range of conditions involving different reservoir and leakage properties and a variety of monitoring setups (Benson et al., 2006; Chabora and Benson, 2008; Nogues et al., 2011; Jung et al., 2013). Researchers also looked into automatic optimization and inversion algorithms to estimate the location and permeability of an unknown leaky pathway based on appropriately positioned above-zone monitoring wells (Sun and Nicot, 2012; Sun et al., 2013), and developed strategies for maximizing the information available from anomalous pressure signals, such as per addition of monitoring wells at optimal locations, or per use of shut-in periods with constant-rate injection periods (Zeidouni and Pooladi-Darvish, 2012a, b). Most feasibility studies mentioned above conclude that large leakage pathways should in theory generate detectable pressure signals if the monitoring wells are not too far away. However, it was also pointed out that the detection of unknown leakage pathways can be challenging in actual field situations, because of subsurface complexities and heterogeneities, noisy data, and uncertainties related to the “expected” reservoir behavior without leakage (Jung et al., 2015).

Above-zone pressure monitoring has recently been applied in a few field demonstration projects. For example, at the SECARB Phase II project in Cranfield, one monitoring well was dedicated to

measure pressure and temperature in the storage formation as well as in the overlying reservoir separated by a 120 m thick caprock (Meckel and Hovorka, 2009, 2010). The observed above-zone pressure was relatively stable during the first three months of injection, but then gradually increased to values that appeared anomalous (Tao et al., 2013). At Ketzin, an above-zone monitoring well was drilled into a thin permeable formation overlying the 200 m thick caprock above the CO₂ storage formation (Wiese et al., 2013). Data analysis from this site suggests that no large brine leaks occurred along known existing wells and a nearby fault. Pressure monitoring in units above the injection zones is currently also conducted at the Illinois Basin Decatur Project site, so far demonstrating that there is negligible pressure change in the reservoir overlying the Eau Claire caprock (Senel et al., 2014).

Monitoring of pressure-induced deformations such as land-surface uplift has also been successfully applied to CCS projects. One prominent example is the time-lapse InSAR monitoring conducted at the In Salah site in Algeria, which was used to track the transient evolution of surface deformation induced by continuous CO₂ injection (Vasco et al., 2008a,b). In particular, the InSAR data showed a double-lobed surface deformation around injection well KB-502, an anomalous feature attributed to the opening of a limited-size fracture zone in the thick caprock due to high injection pressure (Vasco et al., 2010; Morris et al., 2011; Rinaldi and Rutqvist, 2013). Realizing the value of measuring deformation to infer subsurface processes and perhaps detect anomalous results, Jung et al. (2013) recently proposed the joint inversion of pressure signal data (which are often available at only a few monitoring locations) together with surface-deformation measurements (which offer much higher spatial resolution). They postulate that when these two complementary data types are both available, the inversion accuracy for leakage detection can be significantly improved.

4. Summary and Conclusions

A great deal of research has been conducted since publication of the IPCC SRCCS. Today, 10 years later, we have gained a solid understanding regarding the technical feasibility and environmental safety of CCS. This paper reviews relevant literature findings since 2005 with emphasis on two main topics: (1) CO₂ migration and trapping, and (2) magnitude and implications of reservoir pressure buildup. Key findings that have significantly advanced our knowledge base relative to the SRCCS are given below.

CO₂ Migration and Trapping:

The fundamental effects of CO₂ injection into deep geologic formations, as well as the main processes of CO₂ migration and trapping, were understood in 2005 and concisely presented in the SRCCS. The body of work represented by the published research over the last ten years in the areas of development and applications of mathematical and numerical modeling of these processes, and in field monitoring and investigation of CO₂ injection tests and industrial GCS operations, has led to increased understanding of GCS, as summarized below.

- Coupled wellbore-reservoir flow modeling approaches that simulate CO₂ phase behavior in the entire wellbore and reservoir have been demonstrated for both injection and well-leakage (e.g., well blowout) scenarios.
- Dryout zone (near-well) halite-precipitation processes have been modeled and simple mitigation approaches, such as pre-flushing with fresh water, and enlarging the near-well high-permeability region, have been proposed and simulated as ways to mitigate precipitation-related injectivity loss.

- Expansion-related cooling of CO₂ in the near-well region during injection has been shown by several researchers to be limited to a few degrees C, and therefore is not expected to cause problems for injectivity by freezing water in the pore space or formation integrity, e.g., through thermal stresses.
- Numerous analytical, semi-analytical, and hybrid analytical-numerical models were developed over the last ten years to model CO₂ plume behavior and trapping with ever-increasing capabilities. Similarly, numerical simulation tools and their applications became ever more sophisticated in addressing specific storage and trapping questions.
- Knowledge and experience gained from observations of field experiments and industrial GCS over the last ten years has allowed researchers to conclude that CO₂ breakthrough to observation wells is usually faster than models predict, that fast-flow paths can evolve with time, and that overall storage efficiency is low, as CO₂ prefers high-permeability flow paths and bypasses low-permeability regions in the reservoir. Nevertheless, low-permeability lenses provide heterogeneity favorable to trapping by preventing buoyant CO₂ rise.
- The inherent uncertainty of geologic systems and various types of (often sparse and potentially noisy) observation data from field tests and industrial GCS are motivating development of a new generation of inverse modeling approaches that can efficiently handle a large number of unknowns, and promise to allow near-real-time estimation of plume migration and trapping during GCS.

Pressure Buildup and Brine Displacement:

Whereas in 2005, research related to pressure buildup and brine displacement in response to CO₂ injection was extremely sparse, the state of the art has significantly evolved since then. A large number of modeling studies have been conducted to better understand the magnitude of reservoir pressure buildup in response to large CO₂ storage projects. A wide range of CO₂ storage scenarios was investigated, including some scenarios assuming that CCS in the future will be applied at a scale that makes a meaningful contribution to global climate change mitigation, and it was realized that there is an important relationship between reservoir pressure and CO₂ storage capacity. Potential implications related to large-scale pressure buildup have been assessed, including concerns about brine leakage and geomechanical damage, and strategies for management of reservoir pressures via brine extraction have been evaluated.

- Modeling studies for large industrial-scale CCS projects have generally demonstrated that injection-induced pressure changes can propagate very far within CO₂ storage formations, possibly affecting entire reservoirs and basins. One important modeling lesson learned is the need for proper definition of hydrogeological boundary conditions, both with regards to the lateral extent of the storage formations (i.e., compartmentalized or open) and the reservoir-scale effective conductivity of the vertical confining units (i.e., to adequately account for pressure bleed-off).
- Lateral and vertical brine migration is not considered a concern for shallower groundwater resources if the sealing units remain competent over the large areas affected by perturbation. However, the potential for pressure-driven brine leakage through localized pathways (e.g., leaky wellbores, faults, areas with less competent seals) needs to be evaluated for CO₂ storage projects, and such evaluation is now a central element of geologic sequestration regulation in the United States.

- In sedimentary basins with interconnected reservoirs, large-scale pressure buildup from CO₂ storage projects can interfere with other subsurface activities operating in the same formation (e.g., geothermal, oil and gas, other CO₂ storage projects). In such cases, pressure interference between individual operations will require effective planning and permitting approaches.
- While to date no harmful induced seismicity has been associated with any of the current CCS demonstration or industrial projects, the potential for fault reactivation in response to fluid injection and large-scale pressure buildup has received increasing attention in the CCS research community. In addition to concerns about ground motion at the surface, slip on existing faults may lead to seal breaching and leakage of CO₂. Researchers are currently working on physics-based simulation approaches for better risk assessment and are also developing best-practice guidelines to evaluate and manage the potential for induced seismicity.
- Environmental and geomechanical concerns related to large-scale pressure buildup may be a limiting factor for CO₂ capacity. Estimates of “volumetric” storage capacity based on the effective pore volume available for safe trapping of CO₂ should be compared with, and perhaps improved by, “dynamic” capacity evaluations on the basis of the expected site- or basin-scale pressure buildup.
- Pressure management strategies involving brine extraction (and in some cases re-injection) can provide an engineering solution in cases where pressure buildup needs to be minimized. Open questions are related to the economic viability of these strategies and the need to handle or dispose of very large volumes of brackish water.
- The measurement of pressure signals and in some cases of pressure-induced deformations has become an important part of the monitoring portfolio of most CCS projects.

Acknowledgment

The authors wish to thank the two anonymous reviewers, as well as Dan Hawkes of Lawrence Berkeley National Laboratory (LBNL), for their careful review of the manuscript and the suggestion of improvements. The work was funded by the Assistant Secretary for Fossil Energy, Office of Sequestration, Hydrogen, and Clean Coal Fuels, National Energy Technology Laboratory (NETL), of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

References

- Arts, R., Eiken, O., Chadwick, A., Thibeau, S., Nooner, S., 2008. Ten years’ experience of monitoring CO₂ injection in the Utsira Sand at Sleipner, offshore Norway. *First Break*, 26, 65–72.
- Ashraf, M., Oladyshkin, S., Nowak, W., 2013. Geological storage of CO₂: global sensitivity analysis and risk assessment using arbitrary polynomial chaos expansion. *Int. J. Greenhouse Gas Control*, 19, 704–719.
- Azizi, E., Cinar, Y., 2013. Approximate analytical solutions for CO₂ injectivity into saline formations. *SPE Reservoir Eval. Eng.*, 16(2), 123–133.
- Bachmann, C., Wössner, J., Wiemer, S., 2009. A new probability-based monitoring system for induced seismicity: Insights from the 2006–2007 Basel earthquake sequence. *Seis. Res. Lett.*, 80(2), 327.
- Bachu, S., 2015. Review of efficiency of CO₂ storage in deep saline aquifers and of factors that affect it. *Int. J. Greenhouse Gas Control*, this issue.

1093 Baklid, A., Korbøl, R., Owren, G., 1996. Sleipner Vest CO₂ disposal, CO₂ injection into a shallow
1094 underground aquifer. SPE36600 paper presented at SPE Annual Technical Conference and
1095 Exhibition, Soc. of Pet. Eng., Denver, CO, USA, October 6–9, 1996.

1096 Bandilla, K., Celia, M., Elliot, T.R., Person, M., Ellet, K., Rupp, J., Gable, C., Dobossy, M., 2012.
1097 Modeling carbon sequestration in the Illinois Basin using a vertically-integrated approach.
1098 Computing and Visualization in Science, 15 (1), 39-51.

1099 Benson, S.M., Trautz, R., Shan, C., 2006. Sensitivity of pressure monitoring for leak detection.
1100 Berkeley, CA; Available at: [http://www.netl.doe.gov/publications/proceedings/06/carbon-](http://www.netl.doe.gov/publications/proceedings/06/carbon-seq/Tech%20Session%20186.pdf)
1101 [seq/Tech%20Session%20186.pdf](http://www.netl.doe.gov/publications/proceedings/06/carbon-seq/Tech%20Session%20186.pdf).

1102 Bergman, M., Winter, E.M., 1995. Disposal of carbon dioxide in aquifers in the U.S. Energy
1103 Convers. Manage., 36, 523–526.

1104 Bergmo, P.E., Grimstad, A.-A., Lindeberg, E., 2011. Simultaneous CO₂ injection and water
1105 production to optimize aquifer storage capacity. Int. J. Greenhouse Gas Control, 5, 555-564.

1106 Birkholzer, J.T., Zhou, Q., Tsang, C.-F., 2009. Large-scale impact of CO₂ storage in deep saline
1107 aquifers: A sensitivity study on the pressure response in stratified systems. Int. J. Greenhouse
1108 Gas Control 3(2), 181-194.

1109 Birkholzer, J.T., Zhou, Q., 2009. Basin-scale hydrogeologic impacts of CO₂ storage: Capacity and
1110 regulatory implications. Int. J. Greenhouse Gas Control, 3(6), 745-756.

1111 Birkholzer, J.T., Zhou, Q., Cortis, A., Finsterle, S., 2010. On the quantification of regional pressure
1112 buildup from large-scale CO₂ storage projects. Proceedings 10th International Conference on
1113 Greenhouse Gas Control Technologies, Amsterdam, The Netherlands, September 2010.

1114 Birkholzer, J.T., Nicot, J.P., Oldenburg, C.M., Zhou, Q., Kraemer, S., Bandilla, K.W., 2011. Brine
1115 flow up a well caused by pressure perturbation from CO₂ storage: Static and dynamic
1116 evaluations. Int. J. Greenhouse Gas Control, 5(4), 850-861.

1117 Birkholzer, J.T., Cihan, A., Zhou, Q., 2012. Impact-driven pressure management via targeted
1118 brine extraction—Conceptual studies of CO₂ storage in saline formations. Int. J. Greenhouse Gas
1119 Control, 7, 168-180.

1120 Birkholzer, J.T., Cihan, A., Bandilla, K., 2014. A tiered area-of-review framework for geologic
1121 carbon sequestration. Greenhouse Gases—Science and Technology, 4(1), 20-35.

1122 Bissell, R., 2012. Overview of subsurface datasets & geomechanical models. Science Advisory
1123 Board Review Meeting for In Salah Gas CO₂ Storage JIP, BP offices – Sunbury on Thames, U.K.,
1124 15th – 16th October 2012.

1125 Boait, F.C., White, N.J., Mickle, M.J., Chadwick, R.A., Neufeld, J.A., Huppert, H.E., 2012. Spatial
1126 and temporal evolution of injected CO₂ at the Sleipner Field, North Sea. J. Geophys. Res., 117,
1127 B03309, DOI: 10.1029/2011JB008603.

1128 Bourcier, W.L., Wolery, T.J., Wolfe, T., Haussmann, C., Buscheck, T.A., Aines, R.D., 2011. A
1129 preliminary cost and engineering estimate for desalinating produced formation water associated
1130 with carbon dioxide capture and storage. Int. J. Greenhouse Gas Control, 5, 1319-1328.

1131 Breunig, H.M., Birkholzer, J.T., Borgia, A., Oldenburg, C.M., Price, P.M., McKone, T.E., 2013.
1132 Regional evaluation of brine management for geologic carbon sequestration. Int. J. Greenhouse
1133 Gas Control, 14, 39–48.

1134 Buckley, S.E., Leverett, M.C., 1942. Mechanism of fluid displacement in sands. Trans. Am. Inst.
1135 Min. Metall. Pet. Eng., 146(1337), 107–116.

1136 Burgmann, R., Rosen, P.A., Fielding, E.J., 2000. Synthetic aperture radar interferometry to
1137 measure Earth's surface topography and its deformation. *Annual Review of Earth and Planetary*
1138 *Sciences*, 28, 169–209, doi:10.1146/annurev.earth.28.1.169.

1139 Burton, M., Bryant, S., 2009. Eliminating buoyant migration of sequestered CO₂ through surface
1140 dissolution: Implementation costs and technical challenges. *SPEREE* 12, 399-407.

1141 Burton, M.M., Kumar, N., Bryant, S., 2008. Time-dependent injectivity during CO₂ storage in
1142 aquifers. Paper 113937 presented at SPE/DOE Symposium on Improved Oil Recovery, Soc. of Pet.
1143 Eng., Tulsa, Okla., 20–23 April.

1144 Buscheck, T.A., Sun, Y., Chen, M., Hao, Y., Wolery, T.J., Bourcier, W., Court, B., Celia, M.A.,
1145 Friedmann, S.J., Aines, R.D., 2012. Active CO₂ reservoir management for carbon storage: Analysis
1146 of operational strategies to relieve pressure buildup and improve injectivity. *Int. J. Greenhouse*
1147 *Gas Control*, 6, 230-245.

1148 Butsch, R., Brown, A.L., Bryans, B., Kolb, C., 2013. The value of integration—lessons learned
1149 through comparing and contrasting monitoring technologies deployed at Cranfield. *Int. J.*
1150 *Greenhouse Gas Control*, 18, 409-420.

1151 Cappa, F., Rutqvist, J., 2012. Seismic rupture and ground accelerations induced by CO₂ injection in
1152 the shallow crust. *Geophys. J. Int.*, 190(3), 1784-1789.

1153 Carrigan, C.R., Yang, X., LaBrecque, D.J., Larsen, D., Freeman, D., Ramirez, A.L., Daily, W., Aines,
1154 R., Newmark, R., Friedmann, J., Hovorka, S., 2013. Electrical resistance tomographic monitoring
1155 of CO₂ movement in deep geologic reservoirs. *Int. J. Greenhouse Gas Control*, 18, 401–408.

1156 Cavanagh, A., Ringrose, P., 2011. Simulation of CO₂ distribution at the In Salah storage site using
1157 high-resolution field-scale models. *Energy Procedia*, 4, 3730-3737.

1158 Cavanagh, A., Rostron, B., 2013. High-resolution simulations of migration pathways and the
1159 related potential well risk at the IEAGHG Weyburn–Midale CO₂ storage project. *Int. J.*
1160 *Greenhouse Gas Control*, 16, S15-S24.

1161 Cavanagh, A.J., Haszeldine, R.S., 2014. The Sleipner storage site: Capillary flow modeling of a
1162 layered CO₂ plume requires fractured shale barriers within the Utsira Formation. *Int. J.*
1163 *Greenhouse Gas Control*, 21, 101-112.

1164 Celia, M.A., Nordbotten, J.M., 2009. Practical modeling approaches for geological storage of
1165 carbon dioxide. *Groundwater*, 47(5), 627-638.

1166 Celia, M.A., Nordbotten, J.M., Court, B., Dobossy, M., Bachu, S., 2011. Field-scale application of a
1167 semi-analytical model for estimation of CO₂ and brine leakage along old wells. *Int. J. Greenhouse*
1168 *Gas Control*, 5, 257-269.

1169 Chabora, E., Benson, S.M., 2008. Monitoring pressure transients in zones overlying CO₂ storage
1170 reservoirs as a means of leak detection and diagnosis. *Proceeding of Seventh Annual Conference*
1171 *on Carbon Capture and Sequestration*, Pittsburgh, PA, May 7, 2008.

1172 Chadwick, R.A., Zweigel, P., Gregerson, U., Kirby, G., Holloway, S., Johannessen, P., 2004.
1173 Geological reservoir characterization of a CO₂ storage site: The Utsira Sand, Sleipner, northern
1174 North Sea. *Energy*, 29, 1371–1381.

1175 Chadwick, R.A., Williams, G.A., Williams, J.D.O., Noy, D.J., 2012. Measuring pressure
1176 performance of a large saline aquifer during industrial-scale CO₂ injection: The Utsira Sand,
1177 Norwegian North Sea. *Int. J. Greenhouse Gas Control*, 10, 374–388.

1178 Cihan, A., Bianchi, M., Birkholzer, J.T., 2015. Optimal well placement and brine extraction for
1179 pressure management during CO₂ sequestration. *Int. J. Greenhouse Gas Control* (submitted).

1180 Cihan, A., Birkholzer, J., Illangasekare, T. H., Zhou, Q., 2014. A modeling approach to represent
1181 hysteresis in capillary pressure-saturation relationship based on fluid connectivity in void space.
1182 *Water Resources Research*, 50(1), 119-131.

1183 Class, H., Ebigbo, A., Helmig, R., Dahle, H.K., Nordbotten, J.M., Celia, M.A., Audigane, P., Darcis,
1184 M., Ennis-King, J., Fan, Y., Flemisch, B., Gasda, S.E., Jin, M., Krug, S., Labregere, D., Beni, A.N.,
1185 Pawar, R.J., Sbaji, A., Thomas, S.G., Trenty, L., Wei, L., 2009. A benchmark study on problems
1186 related to CO₂ storage in geologic formations: Summary and discussion of the results.
1187 *Computational Geosciences*, 13, 409–434, DOI: 10.1007/s10596-009-9146-x.

1188 Court, B., Celia, M.A., Nordbotten, J.N., Elliot, T.R., 2011. Active and integrated management of
1189 water resources throughout CO₂ capture and sequestration operations. 10th International
1190 Conference on Greenhouse Gas Control Technologies, GHGT-10, *Energy Procedia*, 4, 4221-4229.

1191 Daley, T., Solbau, M., Ajo-Franklin, R.T., Benson, J.B.S.M., 2007. Continuous active-source seismic
1192 monitoring of CO₂ injection in a brine aquifer. *Geophysics*, 72(A57–A61),
1193 <http://dx.doi.org/10.1190/1.2754716>.

1194 Dempsey, D., Kelkar, S., Pawar, R., 2014. Passive injection: A strategy for mitigating reservoir
1195 pressurization, induced seismicity and brine migration in geologic CO₂ storage. *Int. J.*
1196 *Greenhouse Gas Control*, 28, 96-113.

1197 Dentz, M., Tartakovsky, D.M., 2009. Abrupt-interface solution for carbon dioxide injection into
1198 porous media. *Transp. Porous Media*, 79(1), 15-27.

1199 Doetsch, J., Kowalsky, M.B., Doughty, C., Finsterle, S., Ajo-Franklin, J.A. Carrigan, C.A., Yang, X.,
1200 Hovorka, S.D., Daley, T.M., 2013. Constraining CO₂ migration by coupled modeling and inversion
1201 of ERT and gas composition data. *Int. J. Greenhouse Gas Control*, 18, 510–522.

1202 Doughty, C., Freifeld, B.M., Trautz, R.C., 2008. Site characterization for CO₂ geologic storage and
1203 vice versa—The Frio Brine Pilot, Texas, USA as a case study. *Environ. Geol.*, 54 (8), 1635–1656.

1204 Doughty, C., 2007. Modeling geologic storage of carbon dioxide: Comparison of non-hysteretic
1205 and hysteretic characteristic curves. *Energy Convers. Manage.*, 48(6), 1768-1781.

1206 Doughty, C., 2010. Investigation of CO₂ plume behavior for a large-scale pilot test of geologic
1207 carbon storage in a saline formation. *Trans. Porous Media*, 82, 49-76.

1208 Doughty, C., Freifeld, B.M., 2013. Modeling CO₂ injection at Cranfield, Mississippi: Investigation
1209 of methane and temperature effects. *Greenhouse Gases: Science and Technology*, 3(6), 475-490.

1210 EPA (Environmental Protection Agency), 2010. Federal Register, 40 CFR Parts 124, 144, 145, et
1211 al., Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon
1212 Dioxide (CO₂) Geologic Sequestration (GS) Wells, Final Rule, December 10, 2010.

1213 EPA (Environmental Protection Agency), 2013. Underground Injection Control (UIC) Program
1214 Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and
1215 Operators, EPA, Office of Water (4606M), EPA 816-R-13-005, May 2013.

1216 Espinet, A., Shoemaker, C., Doughty, C., 2013. Estimation of plume distribution for carbon
1217 sequestration using parameter estimation with limited monitoring data. *Water Resour. Res.*,
1218 49(7), 4442–4464.

1219 EU Directive, 2009. Directive 2009/31/EC of the European Parliament and of the Council of 23
1220 April 2009 on the Geological Storage of Carbon Dioxide, [http://eur-lex.europa.eu/legal-](http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32009L0031)
1221 [content/EN/TXT/?uri=CELEX:32009L0031](http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32009L0031).

1222 Finley, R. J., 2014. An overview of the Illinois Basin–Decatur project. *Greenhouse Gases: Science*
1223 *and Technology*, 4(5), 571-579.

1224 Flett, M., Beacher, G., Brantjes, J., Burt, A., Dauth, C., Koelmeyer, F., Lawrence, R., Leigh, S.,
1225 McKenna, J., Gurton, R., Robinson, I., Tankersley, T., 2008. Gorgon project—subsurface
1226 evaluation of carbon dioxide disposal under Barrow Island. SPE Asia Pacific Oil and Gas
1227 Conference, SPE 116372, Perth, Australia, October 20–22, 2008.

1228 Förster, A., Schöner, R., Förster, H.-J., Norden, B., Blaschke, A.-W., Luckert, J., Beutler, G., Gaupp,
1229 R., Rhede, D., 2010. Reservoir characterization of a CO₂ storage aquifer: the Upper Triassic
1230 Stuttgart Formation in the Northeast German Basin. *Marine and Petroleum Geology*, 27, 2156–
1231 2172.

1232 Freifeld, B.M., Trautz, R.C., Yousif, K.K., Phelps, T.J., Myer, L.R., Hovorka, S.D., Collins, D., 2005.
1233 The U-tube: A novel system for acquiring borehole fluid samples from a deep geologic CO₂
1234 sequestration experiment. *J. Geophys. Res.*, 110, B10203,
1235 <http://dx.doi.org/10.1029/2005JB003735>.

1236 Gasda, S. E., Nordbotten, J. M., Celia, M. A., 2009. Vertical equilibrium with sub-scale analytical
1237 methods for geological CO₂ sequestration. *Computational Geosciences*, 13(4), 469-481.

1238 Gasda, S.E., Nordbotten, J.M., Celia, M.A., 2011. Vertically averaged approaches for CO₂
1239 migration with solubility trapping. *Water Resources Research*, 47 (5), W05528.

1240 Gasda, S.E., Nordbotten, J.M., Celia, M.A., 2012. Application of simplified models to CO₂
1241 migration and immobilization in large-scale geological systems. *Int. J. Greenhouse Gas Control*, 9,
1242 72-84.

1243 GCCSI, 2014. The Global Status of CCS, Summary Report, Global Carbon Capture and Storage
1244 Institute, February 2014, [http://www.globalccsinstitute.com/publications/global-status-ccs-](http://www.globalccsinstitute.com/publications/global-status-ccs-february-2014)
1245 [february-2014](http://www.globalccsinstitute.com/publications/global-status-ccs-february-2014).

1246 Geiger, S., Dentz, M., Neuweiler, I., 2013. A novel multi-rate dual-porosity model for improved
1247 simulation of fractured and multi-porosity reservoirs. *SPE Journal*, 18(4), 670-684, DOI:
1248 10.2118/148130-PA.

1249 Giorgis, T., Carpita, M., Battistelli, A., 2007. 2D modeling of salt precipitation during the injection
1250 of dry CO₂ in a depleted gas reservoir. *Energy Convers. Manage.*, 48, 1816–1826, DOI:
1251 10.1016/j.enconman.2007.01.012.

1252 Gunter, W.D., Bachu, S., Law, D.H.-S., Marwaha, V., Drysdale, D.L., McDonald, D.E., McCann, T.J.,
1253 1996. Technical and economic feasibility of CO₂ disposal in aquifers within the Alberta
1254 Sedimentary Basin, Canada. *Energy Convers. Manage.*, 37(6-8), 1135–1142.

1255 Han, W.S., Stillman, G.A., Lu, M., Lu, C., McPherson, B.J., Park, E., 2010. Evaluation of potential
1256 non-isothermal processes and heat transport during CO₂ sequestration. *J. Geophys. Res.*, 115,
1257 B07209, DOI: 10.1029/2009JB00674.

1258 Han, W.S., Kim, K.Y., Park, E., McPherson, B.J., Lee, S.Y., Park, M.H., 2012. Modeling of
1259 spatiotemporal thermal response to CO₂ injection in saline formations: Interpretation for
1260 monitoring. *Transp. Porous Media*, 93, 381–399.

1261 Hansen, O., Gilding, D., Nazarian, B., Osdal, B., Ringrose, P., Kristoffersen, J.B., Eiken, O., Hansen,
1262 H., 2013. Snøhvit: The history of injecting and storing 1 Mt CO₂ in the fluvial Tubåen Formation.
1263 Energy Procedia, 37, 3565–3573.

1264 Harto, C.B., Veil, J.A., 2011. Management of Extracted Water from Carbon Sequestration
1265 Projects, Argonne National Laboratory Report, ANL/EVS/R-11/1, January 2011, 38 pages.

1266 Harto, C.B., Veil, J.A., McNemar, A.T., 2011. Extracting Water from Carbon Sequestration
1267 Projects: Quantities, Costs, and Environmental Considerations, Abstract from 10th Annual
1268 Conference on Carbon Capture & Sequestration, May 2-5, 2011, Pittsburgh, PA.

1269 Hesse, M.A., Orr, F.M., Tchelepi, H.A., 2008. Gravity currents with residual trapping. J. Fluid
1270 Mech., 611, 35-60.

1271 Hosseini, S.A., Lashgari, H., Choi, J.-W., Nicot, J.-P., Lu, J., Hovorka, S.D., 2013. Static and dynamic
1272 reservoir modeling for geological CO₂ sequestration at Cranfield, Mississippi, U.S.A. Int. J.
1273 Greenhouse Gas Control, 18, 449–462.

1274 Houseworth, J.E., 2012. Matched boundary extrapolation solutions for CO₂ well-injection into a
1275 saline aquifer. Transp. Porous Media, 91(3), 813-831.

1276 Hovorka, S.D., Benson, S.M., Doughty, C., Freifeld, B.M., Sakurai, S., Daley, T.M., Kharaka, Y.K.,
1277 Holtz, M.H., Trautz, R.C., Nance, H.S., Meyer, L.R., Knauss, K.G., 2006. Measuring permanence of
1278 CO₂ storage in saline formations—The Frio Experiment. Environ. Geosci., 13(2), 105–121.

1279 Hovorka, S.D., 2009. Frio Brine Pilot: the First U.S. Sequestration Test. Southwest Hydrology, 26-
1280 31

1281 Hovorka, S.D., Meckel, T.A., Trevi, R.H., 2013. Monitoring a large-volume injection at Cranfield,
1282 Mississippi—Project design and recommendations. Int. J. Greenhouse Gas Control, 18, 345–360.

1283 Huang, X., Bandilla, K.W., Celia, M.A., Bachu, S., 2014. Basin-scale modeling of CO₂ storage using
1284 models of varying complexity. Int. J. Greenhouse Gas Control, 20, 73-86.

1285 Hurter, S., Labregere, D., Berge, J., 2007. Simulations for CO₂ injection projects with
1286 compositional simulator, SPE-108540-MS paper presented at Offshore Europe 2007 Conference,
1287 Soc. of Petrol. Eng., Aberdeen, Scotland, September 4-7, 2007.

1288 Iding, M., Ringrose, P., 2010. Evaluating the impact of fractures on the performance of the In
1289 Salah CO₂ storage site. Int. J. Greenhouse Gas Control, 4, 242–248.

1290 IEAGHG, 2002. Opportunities for early application of CO₂ sequestration technology, Report
1291 PH4/10, September 2002.

1292 IEAGHG, 2010. Pressurization and Brine Displacement Issues for Deep Saline Formation CO₂
1293 Storage. IEAGHG Report 2010/15, November 2010.

1294 IEAGHG, 2013a. Induced Seismicity and Its Implications for CO₂ Storage Risk. IEAGHG Report
1295 2013/09, June 2013.

1296 IEAGHG, 2013b. Interaction of CO₂ Storage with Subsurface Resources. IEAGHG Report 2013/08,
1297 April 2013.

1298 IEA (International Energy Agency), 2004. Prospects for CO₂ Capture and Storage, 252 pp.

1299 IPCC (Intergovernmental Panel on Climate Change), 2005. IPCC Special Report on Carbon Dioxide
1300 Capture and Storage. Cambridge University Press, New York.

1301 Ivandic, M., Juhlin, C., Lüth, S., Bergmann, P., Kashubin, A., 2013. Geophysical monitoring of CO₂
1302 at the Ketzin Storage Site—The results of the second 3D repeat seismic survey. 75th EAGE
1303 Conference & Exhibition Incorporating SPEEUROPEC 2013, London, UK, June 10–13.

1304 Ivanova, A., Kashubin, A., Juhojuntti, N., Kummerow, J., Henninges, J., Juhlin, C., Lüth, S., Ivandic,
1305 M., 2012. Monitoring and volumetric estimation of injected CO₂ using 4D seismic, petrophysical
1306 data, core measurements and well logging: a case study at Ketzin, Germany. *Geophys.*
1307 *Prospecting*, 60, 957–973.

1308 Jain, L., Bryant, S.L., 2011. Optimal design of injection/extraction wells for the surface dissolution
1309 CO₂ storage strategy. *Energy Procedia*, 4, 4299–4306.

1310 Jiang, P. Li, X., Xu, R., Wang, R., Chen, M., Wang, H., Ruan, B., 2014. Thermal modeling of CO₂ in
1311 the injection well and reservoir at the Ordos CCS demonstration project, China. *Int. J.*
1312 *Greenhouse Gas Control*, 23, 135–146.

1313 Juanes, R., MacMinn, C.W., Szulczewski, M.L., 2010. The footprint of the CO₂ plume during
1314 carbon dioxide storage in saline aquifers: storage efficiency for capillary trapping at the basin
1315 scale. *Transp. Porous Media*, 82(1), 19–30.

1316 Juanes, R., Spiteri, E.J., Orr, F.M., Blunt, M.J., 2006. Impact of relative permeability hysteresis on
1317 geological CO₂ storage. *Water Resour. Res.*, 42(12), W12418.

1318 Juhlin, C., Giese, R., Zinck-Jørgensen, K., Cosma, C., Kazemeini, H., Juhojuntti, N., Lüth, S., Norden,
1319 B., Förster, A., 2007. 3D baseline seismics at Ketzin, Germany: the CO₂SINK project. *Geophysics*,
1320 72, 121–132.

1321 Jung, Y., Zhou, Q., Birkholzer, J.T., 2013. Early detection of brine and CO₂ leakage through
1322 abandoned wells using pressure and surface-deformation monitoring data: Concept and
1323 demonstration. *Adv. Water Resour.*, 62, 555–569.

1324 Jung, Y., Zhou, Q., Birkholzer, J.T., 2015. On the detection of leakage pathways in geological CO₂
1325 storage systems using pressure monitoring data: Impact of model uncertainties. *Adv. Water*
1326 *Resour.* (submitted).

1327 Kaldi, J., Bachu, S., 2010. Geologic carbon sequestration: Prediction and verification.
1328 AAPG/SEG/SPE Hedberg Conference, Vancouver, Canada (2009). Available at:
1329 <http://www.aapg.org/education/hedberg/vancouver/index.cfm> [December, 2010].

1330 Kempka, T., Kuhn, M., 2013. Numerical simulations of CO₂ arrival times and reservoir pressure
1331 coincide with observations from the Ketzin pilot site, Germany. *Environ. Earth Sci.*, 70(8), 3675–
1332 3685.

1333 Kim, K., Han, W.S., Oh, J., Kim, T., Kim, J.C., 2012. Characteristics of salt-precipitation and the
1334 associated pressure build-up during CO₂ storage in saline aquifers. *Trans. Porous Media*, 92(2),
1335 397–418.

1336 Kitanidis, P.K., 2014. Compressed state kalman filter for large systems. *SIAM/ASA Journal on*
1337 *Uncertainty Quantification* (under review).

1338 Kitanidis, P.K., Lee, J., 2014. Principal component geostatistical approach for large-dimensional
1339 inverse problems. *Water Resour. Res.*, 50, 5428–5443, DOI: 10.1002/2013WR014630.

1340 Kokkinaki, A., Li, J., Zhou, Q., Birkholzer, J.T., Kitanidis, P.K., 2014. Large-scale characterization of
1341 geologic formations for CO₂ injection using Compressed State Kalman Filter. The 2014 AGU Fall
1342 Meeting, San Francisco, CA, December 14–19.

1343 Korbol, R., Kaddour, A., 1995. Sleipner Vest CO₂ disposal-injection of removed CO₂ into the Utsira
1344 Formation. *Energy Convers. Mgmt.*, 36(6-9), 509-512.

1345 Li, J., Li, X., 2014. Analysis of U-tube sampling data based on modeling of CO₂ injection into CH₄
1346 saturated aquifers. *Greenhouse Gas Sci. Technol.* DOI: 10.1002/ghg.1454.

1347 Litynski, J., Plasynski, S., Spangler, L., Finley, R., Steadman, E., Ball, D., Nemeth, K., McPherson,
1348 B., Myer, L., 2009. U.S. Department of Energy's Regional Carbon Sequestration Program:
1349 Overview. *Energy Procedia*, 1, 3959 – 3967.

1350 Litynski, J., Rodosta, T., Vikara, D., Srivastava, R., 2013. U.S. Department of Energy's R&D
1351 Program to Develop Infrastructure for Carbon Storage: Overview of the Regional Carbon
1352 Sequestration Partnerships and Other R&D Field Projects. *Energy Procedia*, 37, 6527-6543.

1353 Liu, Y., Wang, L., Yu, B., 2010. Sharp front capturing method for carbon dioxide plume
1354 propagation during injection into a deep confined aquifer. *Energy & Fuels*, 24(2), 1431-1440.

1355 Liu, G., Gorecki, C.D., Saini, D., Bremer, J.M., Klapperich, R.J., Braunberge, J.R., 2013. Four-case
1356 study of water extraction from CO₂ storage reservoirs. 10th International Conference on
1357 Greenhouse Gas Control Technologies, GHGT-11, *Energy Procedia*, 37, 4518-4525.

1358 Lu, J., Cook, P.J., Hosseini, S.A., Yang, C., Romanak, K.D., Zhang, T., Freifeld, B.M., Smyth, R.C.,
1359 Zeng, H., Hovorka, S.D., 2012. Complex fluid flow revealed by monitoring CO₂ injection in a fluvial
1360 formation. *J. Geophys. Res.*, 117, B03208, DOI: 10.1029/2011JB008939.

1361 Lu, M., Connell, L.D., 2008. Non-isothermal flow of carbon dioxide in injection wells during
1362 geological storage. *Int. J. Greenhouse Gas Control*, 2(2), 248-258.

1363 Lu, M., Connell, L.D., 2014. Transient, thermal wellbore flow of multispecies carbon dioxide
1364 mixtures with phase transition during geological storage. *Int. J. Multiphase Flow*, 63, 82-92.

1365 Majer, E.L., Nelson, J., Robertson-Tait, A., Savy, J., Wong, I., 2012. Protocol for Addressing
1366 Induced Seismicity Associated with Enhanced Geothermal Systems. DOE/EE-0662. U.S.
1367 Department of Energy. Available at:
1368 www1.eere.energy.gov/geothermal/pdfs/geothermal_seismicity_protocol_012012.pdf.

1369 Martens, S., Kempka, T., Liebscher, A., Lüth, S., Möller, F., Myrtilinen, A., Norden, B., Schmidt-
1370 Hattenberger, C., Zimmer, M., Kühn, M., Ketzin Group, 2012. Europe's longest-operating on-
1371 shore CO₂ storage site at Ketzin, Germany: A progress report after three years of injection.
1372 *Environ. Earth Sci.*, 67(2), 323-334.

1373 Massonnet, D., Feigl, K.L., 1998. Radar interferometry and its application to changes in the
1374 earth's surface. *Reviews of Geophysics*, 36 (4), 444–500.

1375 Mathias, S.A., Hardisty, P.E., Trudell, M.R., Zimmerman, R.W., 2009. Screening and selection of
1376 sites for CO₂ sequestration based on pressure buildup. *Int. J. Greenhouse Gas Control*, 3(5), 577–
1377 585.

1378 Mathias, S.A., Gluyas, J.G., Oldenburg, C.M., Tsang, C.-F., 2010. Analytical solution for Joule–
1379 Thomson cooling during CO₂ geo-sequestration in depleted oil and gas reservoirs. *Int. J.*
1380 *Greenhouse Gas Control*, 4(5), 806-810.

1381 Mathias, S.A., Gluyas, J.G., de Miguel, G.J.G.M., Hosseini, S.A., 2011a. Role of partial miscibility
1382 on pressure buildup due to constant rate injection of CO₂ into closed and open brine aquifers.
1383 *Water Resour. Res.*, 47, W12525, doi:10.1029/2011WR011051.

1384 Mathias, S. A., González Martínez de Miguel, G. J., Thatcher, K. E., Zimmerman, R. W. 2011b.
1385 Pressure Buildup During CO₂ Injection into a Closed Brine Aquifer. *Transport in Porous Media*,

1386 89(3), 383–397.

1387 Mathieson, A., Midgley, J., Dodds, K., Wright, I., Ringrose, P., 2010. CO₂ sequestration monitoring
1388 and verification technologies applied at Krechba, Algeria. *The Leading Edge*, February 2010, 216–
1389 222.

1390 Maulbetsch, J.S., DiFillipo, M.N., 2010. Performance, Cost, and Environmental Effects of
1391 Saltwater Cooling Towers, Public Interest Research Program Final Project Report. California
1392 Energy Commission, CEC-500-2008-043.

1393 Meckel, T.A., Hovorka, S.D., 2009. Results of continuous downhole monitoring (PDG) at a field-
1394 scale CO₂ demonstration project, Cranfield, MS. SPE International Conference on CO₂ Capture,
1395 Storage, and Utilization, San Diego, California, 4–9 November.

1396 Meckel, T.A., Hovorka, S.D., 2010. Above-zone pressure monitoring as a surveillance tool for
1397 carbon sequestration projects. SPE International Conference on CO₂ Capture, Storage, and
1398 Utilization, New Orleans, LA, USA, 10–12 November.

1399 Mehnert, E., Damico, J., Frailey, S., Leetaru, H., Okwen, R., Storsved, B., Valocci, A., 2014. Basin-
1400 scale modeling for CO₂ sequestration in the basal sandstone reservoir of the Illinois Basin—
1401 Improving the geologic model. *Energy Procedia* 63, 2949–2960.

1402 Mijic, A., LaForce, T.C., 2012. Spatially varying fractional flow in radial CO₂–brine displacement.
1403 *Water Resour. Res.*, 48, W09503, DOI: 10.1029/2011WR010961.

1404 Mijic, A., LaForce, T.C., Muggeridge, A.H., 2014. CO₂ injectivity in saline aquifers: The impact of
1405 non-Darcy flow, phase miscibility, and gas compressibility. *Water Resour. Res.*, 50, 4163–4185,
1406 DOI: 10.1002/2013WR014893.

1407 Morris, J.P., Hao, Y., Foxall, W., MacNab, W., 2011. A study of injection induced mechanical
1408 deformation at the In Salah CO₂ storage project. *Int. J. Greenhouse Gas Control*, 5, 270–280,
1409 <http://dx.doi.org/10.1016/j.ijggc.2010.10.004>.

1410 Muller, N., Ramakrishnan, T.S., Boyd, A., Sakruai, S., 2007. Time-lapse carbon dioxide monitoring
1411 with pulsed neutron logging. *Int. J. Greenhouse Gas Control* 1, 456–472.

1412 NAS (National Academy of Sciences), 2012. Induced Seismicity Potential in Energy Technologies,
1413 NAS Board on Earth Sciences and Resources, Committee on Induced Seismicity Potential in
1414 Energy Technologies, National Academies Press, 500 Fifth Street, NW, Washington, D.C. 20001.

1415 Nicot, J.-P., 2008. Evaluation of large-scale CO₂ storage on fresh-water sections of aquifers: An
1416 example from the Texas Gulf Coast Basin. *Int. J. Greenhouse Gas Control*, 2(4), 582–593.

1417 Nicot, J.P., Duncan, I.J., 2008. Science-based permitting of geological sequestration of CO₂ in
1418 brine reservoirs in the U.S. *Environmental Science & Policy*, 11, 14–24.

1419 Nicot J.-P., Oldenburg, C.M., Houseworth, J.E., Choi, J.-W., 2013. Analysis of potential leakage
1420 pathways at the Cranfield, MS, U.S.A., CO₂ sequestration site. *Int. J. Greenhouse Gas Control*, 18,
1421 388–400.

1422 Nogues, J.P., Nordbotten, J.M., Celia, M.A. 2011. Detecting leakage of brine or CO₂ through
1423 abandoned wells in a geological sequestration operation using pressure monitoring wells. *Energy*
1424 *Procedia*, 4, 3620–3627.

1425 Noh, M., Lake, L., Bryant, S., Araque-Martinez, A., 2007. Implications of coupling fractional flow
1426 and geochemistry for CO₂ injection in aquifers. *SPE Reservoir Eval. Eng.*, 10(4), 406–414.

1427 Nordbotten, J.M., Celia, M.A., 2006. Similarity solutions for fluid injection into confined aquifers.
1428 *J. Fluid Mech.*, 561, 307–327.

1429 Nordbotten, J.M., Celia, M.A., Bachu, S., 2005. Injection and storage of CO₂ in deep saline
1430 aquifers: A analytical solution for CO₂ plume evolution during injection. *Transp. Porous Media*,
1431 58(3), 339–360.

1432 Nordbotten, J.M., Dahle, H.K., 2011. Impact of the capillary fringe in vertically integrated models
1433 for CO₂ storage. *Water Resour. Res.*, 47, W02537, DOI: 10.1029/2009WR008958.

1434 Nordbotten, J.M., Flemisch, B., Gasda, S.E., Nilsen, H.M., Fan, Y., Pickup, G.E., Wiese, B., Celia,
1435 M.A., Dahle, H.K., Eigestad, G.T., Pruess, K. 2012. Uncertainties in practical simulation of CO₂
1436 storage. *Int. J. Greenhouse Gas Control*, 9 (2012) 234-242.

1437 Norden, B., Förster, A., Vu-Hang, D., Marcelis, F., Springer, N., Le Nir, I., 2010. Lithological and
1438 petrophysical core-log interpretation in CO₂SINK, the European CO₂ onshore research storage
1439 and verification project. *SPE Reservoir Eval. Eng.*, 13, 179–192.

1440 NRAP, 2013. Second Generation Toolset for Calculation of Induced Seismicity Risk Profiles,
1441 National Risk Assessment Partnership, Technical Report Series, TRS 2013-0515, May 2012.

1442 Okwen, R.T., Stewart, M.T., Cunningham, J.A., 2010. Analytical solution for estimating storage
1443 efficiency of geologic sequestration of CO₂. *Int. J. Greenhouse Gas Control*, 4, 102–107.

1444 Oladyshkin, S., Class, H., Nowak, W., 2013. Bayesian updating via Bootstrap filtering combined
1445 with data-driven polynomial chaos expansions: methodology and application to history matching
1446 for carbon dioxide storage in geological formations. *Computational Geosciences*, 17(4), 671-687.

1447 Oldenburg, C.M., 2007. Joule-Thomson cooling due to CO₂ injection into natural gas reservoirs.
1448 *Energy Convers. Manage.*, 48(6), 1808-1815.

1449 Oldenburg, C.M., Doughty, C., 2011. Injection, flow, and mixing of CO₂ in porous media with
1450 residual gas. *Transp. Porous Media*, 90(1), 201-218.

1451 Oldenburg, C.M., Doughty, C., Spycher, N., 2013. The role of CO₂ in CH₄ exsolution from deep
1452 brine: Implications for geologic carbon sequestration. *Greenhouse Gas Sci. Technol.*, 3(5), 359-
1453 377.

1454 Oldenburg, C.M., Cihan, A., Zhou, Q., Fairweather, S., and Spangler, L.H., 2014. Delineating area
1455 of review in a system with pre-injection relative overpressure, in *Proceedings of GHGT-12*,
1456 Austin, Texas, 5-9 October, 2014, and *Energy Procedia*, 63 (2014), 3715-3722.

1457 Pan, L., 2011. T2Well/ECO2N Version 1.0: Multiphase and Non-Isothermal Model for Coupled
1458 Wellbore-Reservoir Flow of Carbon Dioxide and Variable Salinity Water. Lawrence Berkeley
1459 National Laboratory, Berkeley, CA.

1460 Pan, L., Oldenburg, C.M., Pruess, K., Wu, Y.-S., 2011. Transient CO₂ leakage and injection in
1461 wellbore-reservoir systems for geologic carbon sequestration. *Greenhouse Gas Sci. Technol.*,
1462 1(4), 335-350.

1463 Person, M., Banerjee, A., Rupp, J., Medina, C., Lichtner, P., Gable, C., Pawar, R., Celia, M.,
1464 McIntosh, J., Bense, V., 2010. Assessment of basin-scale hydrologic impacts of CO₂
1465 sequestration, Illinois Basin. *Int. J. Greenhouse Gas Control*, 4, 840-854.

1466 Petvipusit, K.R., Elsheikh, A.H., Laforce, T.C., King, P.R., Blunt, M.J., 2014. Robust optimisation of
1467 CO₂ sequestration strategies under geological uncertainty using adaptive sparse grid surrogates.
1468 *Comput. Geosci.*, 18, 763–778.

1469 Preston, C., Monea, M., 2005. IEA GHG Weyburn CO₂ monitoring and storage project. *Fuel*
1470 *Processing Technology*, 86(14-15), 1547-1568.

1471 Pruess, K., 2009. Formation dry-out from CO₂ injection into saline aquifers: 2. Analytical model
1472 for salt precipitation. *Water Resour. Res.*, 45, W03403, DOI: 10.1029/2008WR007102.

1473 Pruess, K., 2011. Integrated modeling of CO₂ storage and leakage scenarios including transitions
1474 between super- and subcritical conditions, and phase change between liquid and gaseous CO₂.
1475 *Greenhouse Gas Sci. Technol.*, 1(3), 237-247.

1476 Pruess, K., and Garcia, J. 2002. Multiphase flow dynamics during CO₂ disposal into saline
1477 aquifers, *Environmental Geology*, 42(2-3), 282-295.

1478 Pruess, K., Xu, T., Apps, J., García, J., 2003. Numerical modeling of aquifer disposal of CO₂. Paper
1479 SPE 83695, *SPE Journal*, 49–60.

1480 Pruess, K., Garcia, J., Kovscek, T., Oldenburg, C.M., Rutqvist, J., Steefel, C., Xu, T., 2004. Code
1481 intercomparison builds confidence in numerical simulation models for geologic disposal of CO₂.
1482 *Energy*, 29(9-10), 1431-1444.

1483 Pruess, K., Muller, N., 2009. Formation dry-out from CO₂ injection into saline aquifers: 1. Effects
1484 of solids precipitation and their mitigation. *Water Resour. Res.*, 45, W03402, DOI:
1485 10.1029/2008WR007101.

1486 Pruess, K., Nordbotten, J.M., 2011. Numerical simulation studies of the long-term evolution of a
1487 CO₂ plume in a saline aquifer with a sloping caprock. *Transp. Porous Media*, 90(1), 135-151.

1488 Rinaldi, A.P., Rutqvist, J., 2013. Modeling of deep fracture zone opening and transient ground
1489 surface uplift at KB-502 CO₂ injection well, In Salah, Algeria. *Int. J. Greenhouse Gas Control*, 12,
1490 155–167.

1491 Rinaldi, A.P., Rutqvist, J., Cappa, F., 2014. Geomechanical effects on CO₂ leakage through fault
1492 zones during large-scale underground injection. *Int. J. Greenhouse Gas Control*, 20, 117-131.

1493 Ringrose, P., Atbi, M., Mason, D., Espinassous, M., Myhrer, O., Iding, M., Mathieson, A., Wright,
1494 I., 2009. Plume development around well KB-502 at the In Salah CO₂ storage site. *First Break*, 27,
1495 85-89.

1496 Rodosta, T., Litynski, J., Plasynski, S., Spangler, L., Finley, R., Steadman, E., Ball, D., Hill, G.,
1497 McPherson, B., Burton, E., Vikara D., 2011. U.S. Department of Energy's Regional Carbon
1498 Sequestration Program: Update on Validation and Demonstration Phases. *Energy Procedia*, 4,
1499 3457–3464.

1500 Rucci, A., Vasco, D.W., Novali, F., 2013. Monitoring the geologic storage of carbon dioxide using
1501 multicomponent SAR interferometry. *Geophys. J. Int.*, 193, 197–208, DOI: 10.1093/gji/ggs112.

1502 Rutqvist, J., 2012. The geomechanics of CO₂ storage in deep sedimentary formation. *J. Geotechn.*
1503 *Geol. Eng.*, 30 (3), 525–551.

1504 Saadatpoor, E., Bryant, S.L., Sepehrnoori, K., 2010. New trapping mechanism in carbon
1505 sequestration. *Transp. Porous Media*, 82(1), 3-17.

1506 Schaefer, F., Walter, L., Class, H., Mueller, C., 2012. The regional pressure impact of CO₂ storage:
1507 A showcase study from the North German Basin. *Environ. Earth Sci.*, 65, 2037-2049.

1508 Schlumberger oilfield glossary, accessed 05 March 2015,
1509 <http://www.glossary.oilfield.slb.com/en/Terms.aspx?LookIn=term%20name&filter=injectivity%20test>.
1510

1511 Senel, O., Chugunov, N., 2012. CO₂ injection in a saline formation: How do additional data
1512 change uncertainties in our reservoir simulation predictions? *Carbon Management Technology*
1513 *Conference*, DOI: 10.7122/151454-MS.

1514 Senel, O., Chugunov, N., 2013. CO₂ injection in a saline formation: Pre-injection reservoir
1515 modeling and uncertainty analysis for Illinois Basin–Decatur Project. *Energy Procedia*, 37, 4598-
1516 4611.

1517 Senel, O., Will, R., Butsch, R.J., 2014. Integrated reservoir modeling at the Illinois Basin – Decatur
1518 Project. *Greenhouse Gas Sci. Technol.*, 4, 662–684.

1519 Singh, V., Cavanagh, A., Hansen, H., Nazarian, B., Iding, M., Ringrose, P., 2010. Reservoir
1520 modeling of CO₂ plume behavior calibrated against monitoring data from Sleipner, Norway. SPE-
1521 134891 presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy,
1522 September 19-22, 2010.

1523 Singh, A.K., Goerke, U.-J., Kolditz, O., 2011. Numerical simulation of non-isothermal
1524 compositional gas flow: application to carbon dioxide injection into gas reservoirs. *Energy*, 36(5),
1525 3446-3458.

1526 Skalmeraas, O., 2014. The Sleipner CCS experience. United Nations Framework Convention on
1527 Climate Change, Bonn, Germany, October 21, 2014.

1528 Sun, A.Y., Nicot, J.P., 2012. Inversion of pressure anomaly data for detecting leakage at geologic
1529 carbon sequestration sites. *Adv. Water Resour.*, 44, 20–29.

1530 Sun, A.Y., Zeidouni, M., Nicot, J.P., Lu, Z., Zhang, D., 2013. Assessing leakage detectability at
1531 geologic CO₂ sequestration sites using the probabilistic collocation method. *Adv. Water Resour.*,
1532 56, 49–60.

1533 Tavakoli, R., Yoon, H., Delshad, M., ElSheikh, A.H., Wheeler, M.F., Arnold, B.W., 2013.
1534 Comparison of ensemble filtering algorithms and null-space Monte Carlo for parameter
1535 estimation and uncertainty quantification using CO₂ sequestration data. *Water Resour. Res.*, 49,
1536 8108–8127, DOI: 10.1002/2013WR013959.

1537 Tao, Q., Bryant, S.L., Meckel, T., 2013. Leakage Fingerprints During Storage: Modeling Above-
1538 zone Measurements of Pressure and Temperature. *Energy Procedia*, 37, 4310–4316.

1539 Thibeau, S., Bachu, S., Birkholzer, J.T., Holloway, S., Neele, F., Zhou, Q., 2014. Using pressure and
1540 volumetric approaches to estimate CO₂ storage capacity in deep saline aquifers. The 12th
1541 International Conference on Greenhouse Gas Technologies, GHGT-12, Austin, TX., October 6-9,
1542 2014.

1543 Tillner, E., Kempka, T., Nakaten, B., Kühn, M. (2013). Brine migration through fault zones: 3D
1544 numerical simulations for a prospective CO₂ storage site in Northeast Germany. *Int. J.*
1545 *Greenhouse Gas Control*. doi:10.1016/j.ijggc.2013.03.012

1546 Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D. e Ennis-King, J., 2011.
1547 CO₂ Storage in a Depleted Gas field: An Overview of the CO₂CRC Otway Project and Initial
1548 Results, *Int. J. Greenhouse Gas Control*, 5, 922–932.

1549 Van der Meer, L.G.H., 1992. Investigations regarding the storage of carbon dioxide in aquifers in
1550 the Netherlands. *Energy Convers. Manage.*, 33 (5–8), 611–618.

1551 Vasco, D.W., Ferretti, A., Novali, F., 2008a. Estimating permeability from quasi-static
1552 deformation: temporal variations and arrival time inversion. *Geophysics*, 73 (6), O37–O52,
1553 <http://dx.doi.org/10.1190/1.2978164>.

1554 Vasco, D.W., Ferretti, A., Novali, F., 2008b. Reservoir monitoring and characterization using
1555 satellite geodetic data: Interferometric synthetic aperture radar observations from the Krechba
1556 field, Algeria. *Geophysics*, 73 (6), WA113–WA122, <http://dx.doi.org/10.1190/1.2981184>.

1557 Vasco, D.W., Rucci, A., Ferretti, A., Novali, F., Bissell, R.C., Ringrose, P.S., Mathienson, A.S.,
1558 Wright, I.W., 2010. Satellite-base measurements of surface deformation reveal fluid flow
1559 associated with the geological storage of carbon dioxide. *Geophys. Res. Lett.*, 37, L03303,
1560 <http://dx.doi.org/10.1029/2009GL041544>.

1561 Verdon, J.P., Kendall, J.M., Stork, A.L., Chadwick, R.A., White, D.J., Bissell, R.C., 2013. Comparison
1562 of geomechanical deformation induced by megatonne-scale CO₂ storage at Sleipner, Weyburn,
1563 and In Salah. *Proc Natl Acad. Sci.*, 110(30), E2762–E2771, DOI: 10.1073/pnas.1302156110.

1564 Vilarrasa, V., Carrera, J., Bolster, D., Dentz, M., 2013. Semianalytical solution for CO₂ plume
1565 shape and pressure evolution during CO₂ injection in deep saline formations. *Transp. Porous*
1566 *Media*, 97(1), 43–65.

1567 Wainwright, H., Finsterle, S., Zhou, Q., Birkholzer, J.T., 2013. Modeling the performance of large-
1568 scale CO₂ storage systems: A comparison of different sensitivity analysis methods. *Int. J.*
1569 *Greenhouse Gas Control*, 17, 189-205.

1570 Walter, L., Binning, P.J., Oladyshkin, S., Flemisch, B., Class, H. (2012). Brine migration resulting
1571 from CO₂ injection into saline aquifers - An approach to risk estimation including various levels of
1572 uncertainty. *Int. J. Greenhouse Gas Control*, 9, 495-506.

1573 Walter, L., Binning, P.J., Class, H. (2013). Predicting salt intrusion into freshwater aquifers
1574 resulting from CO₂ injection - a study on the influence of conservative assumptions. *Adv. Water*
1575 *Resour.*, 62, 543–554.

1576 White, M. D., Bacon, D. H., White, S.K., and Zhang, Z.F., 2013. Fully Coupled Well Models for
1577 Fluid Injection and Production, *Energy Procedia*, 37, 3960-3970.

1578 Wiese, B., Zimmer, M., Nowak, M., Pellizzari, L., Pilz, P., 2013. Well-based hydraulic and
1579 geochemical monitoring of the above zone of the CO₂ reservoir at Ketzin, Germany. *Environ.*
1580 *Earth Sci.*, 70(8), 3709-3726.

1581 Wright, I.W., Mathieson, A.S., Riddiford, F., Bishop, C., 2010. In Salah CO₂ storage JIP: Site
1582 selection, management, field development plan and monitoring overview. Paper presented at
1583 10th International Conference on Greenhouse Gas Control Technologies, Amsterdam,
1584 Netherlands, September 19-23, 2010.

1585 Wu, X., 2014. Shenhua Group's carbon capture and storage (CCS) demonstration. *Mining Report*
1586 150, No. 1/2, DOI: 10.1002/mire.201400006.

1587 Würdemann, H., Möller, F., Kühn, M., Heidug, W., Christensen, N.P., Borm, G., Schilling, F.,
1588 CO₂SINK Group, 2010. CO₂SINK – from site characterisation and risk assessment to monitoring
1589 and verification: One year of operational experience with the field laboratory for CO₂ storage at
1590 Ketzin, Germany. *Int. J. Greenhouse Gas Control* 4, 938–951.

1591 Yamamoto, H., Zhang, K., Karasaki, K., Marui, A., Uehara, H., Nishikawa, N., 2009. Numerical
1592 investigation concerning the impact of CO₂ geologic storage on regional groundwater flow. *Int. J.*
1593 *Greenhouse Gas Control*, 3(5), 586-599.

1594 Zeidouni, M., Pooladi-Darvish, M., Keith, D., 2009. Analytical solution to evaluate salt
1595 precipitation during CO₂ injection in saline aquifers. *Int. J. Greenhouse Gas Control*, 3(5), 600–
1596 611.

1597 Zeidouni, M., Pooladi-Darvish, M., 2012a. Leakage characterization through above-zone pressure
1598 monitoring, 1: Inversion approach. *J. Petrol. Sci. Eng.*, 98-99, 95-106.

1599 Zeidouni, M., Pooladi-Darvish, M., 2012b. Leakage characterization through above-zone pressure
1600 monitoring, 2: Design considerations with application to CO₂ storage in saline aquifers. J. Petrol.
1601 Sci. Eng., 98-99: 69-82.

1602 Zhou, Q., Birkholzer, J.T., Tsang, C.-F., Rutqvist, J., 2008. A method for quick-assessment of CO₂
1603 storage capacity in closed and semi-Closed porous formations. Int. J. Greenhouse Gas Control,
1604 2(4), 626-639.

1605 Zhou, Q., Birkholzer, J.T., Mehnert, E., Lin, Y.-F., Zhang, K., 2010. Modeling basin- and plume-
1606 scale processes of CO₂ storage for full-scale deployment. Ground Water, 48(4), 494-514.

1607 Zhou, Q., Birkholzer, J.T., 2011. On the scale and magnitude of pressure buildup induced by
1608 large-scale geologic storage of CO₂. Greenhouse Gas Sci. Technol., 1, 11-20.

1609 Zoback, M.D., Gorelick, S.M., 2012. Earthquake triggering and large-scale geologic storage of
1610 carbon dioxide. Proc Natl Acad. Sci., 109(26), 10164-10168.

1611 Zoback, M.D., 2012. Managing the seismic risk posed by wastewater disposal. Earth Magazine,
1612 April 2, pp. 38-43. Available at nodrilling.files.wordpress.com/2012/02/zoback-earth.pdf.

1613