Carbon dioxide sequestration in underground formations: review of experimental, modeling, and field studies

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Abstract

Carbon dioxide has gradually found widespread usage in the field of science and engineering while various efforts have focused on ways to combat the menace resulting from the release of this compound in the atmosphere. A major approach to combating this release is by storage in various geological formations ranging from depleted reservoir types such as saline aquifers to other carbon sinks. In this research study, we reviewed the experimental, modeling, and field studies related to the underground storage of CO₂. A considerable amount of research has been conducted in simulating and modeling CO₂ sequestration in the subsurface. This review highlights some of the latest contributions. Additionally, the impact of CO₂ sequestration on its surroundings due to chemical reactions, adsorption, capillarity, hysteresis, and wettability were reviewed. Some major challenges associated with CO₂ injection have also been highlighted. Finally, this work presents a brief history of selected field scale projects such as Sleipner, Weyburn, In Salah, Otway Basin, Snøhvit, Alberta, Boundary Dam, Cranfield, and Ketzin. Thus, this study provides a guide of the CO₂ storage process from the perspectives of experimental, modelling, and existing field studies.

Keywords CO₂ sequestration · Saline aquifers · Capillary trapping · Green house gases · Field scale studies

Introduction

Carbon dioxide (CO₂) sequestration refers to the process of capturing the excess CO₂ present within the atmosphere toward long-term storage. CO₂ storage arises from the need

to mitigate the effects of global warming and serves as an avenue to reduce the rate of accumulation of greenhouse gases (GHG) arising from anthropogenic activities. The presence of these GHGs in the atmosphere can result in environmental pollution (Zhang et al. 2018). Different physical, chemical, and biological processes have been developed to reduce the presence of GHG in the atmosphere. CO₂ is one of the major GHG and accounts for 76.7% (v/v) of the total GHG concentration (Ramanathan 1988). It is reported that 57–72% of the GHG effect on global warming is due to CO₂ emissions (Lashof and Ahuja 1990). The increasing concentration of CO₂ in the atmosphere are being managed using different processes. Examples of these processes include storage of the captured CO₂ using depleted reservoir types such as subsurface saline aquifers (Bachu 2000; Emami-Meybodi et al. 2015), ocean water, and other carbon sinks. These geological storage types received widespread acceptance due to their favorable gas distribution, chemistry, permeability, and porosity required for prolonged CO₂ storage (Mahmoodpour and Rostami 2017; Riaz and Cinar 2014; Soltanian et al. 2016b, 2018a, b). Sedimentary basins are considered to be promising targets for CO₂ storage as

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they have high-porosity and high-permeability layers represented by sandstones, and low-permeable and low-porosity caprocks represented by shale which limit the transfer of CO₂ toward the surface. Subsurface sequestration is the easiest route for large-scale sequestration operations. Oil and gas sites have limited capacity; therefore, saline aquifers provide a very attractive alternative for underground sequestration (Lackner 2003). The high salinity of the aquifers is also an important requirement as this highly saline water cannot be used for drinking (Marini 2006).

Storage of CO₂ in geological formations is called sequestration and it can be achieved in four ways: as a mobile phase within a structural trap, as an aqueous species dissolved in brine, as a precipitated mineral and by capillary entrapment as a residual phase (Bryant et al. 2006).

The first mode requires the presence of an impermeable cap rock which prevents the upward flow of CO₂. This is known as hydrodynamic trapping and is only reliable in cases where oil and gas fields and sedimentary basins are well-characterized.

With the passage of time, the injected CO₂ dissolves into the formation water and the resulting increase in brine density leads to the sinking of the CO₂-laden brine. This process is called solution trapping because the CO₂-laden brine does not reach surface. However, this process takes thousands of years under natural conditions (Ennis-King and Paterson 2002).

The third CO₂ sequestration process is by mineral trapping, in which case it reacts with the rock to form solid carbonates. This process takes place over thousands to billions of years, depending on how reactive the rock is (Egermann et al. 2005).

The final storage mechanism is capillary trapping in which the sequestered CO₂ is trapped at the pore scale by capillary forces. Research has shown that capillary trapping is an efficient storage mechanism. Unlike other mechanisms, all or most of the injected CO₂ is trapped and effectively sequestered in a relatively short period of time (within years or decades). The trapped saturations from these experiments are used to calculate the capillary trapping capacities of underground rocks which serve as storage sites for CO₂. The capillary trapping capacity of a rock is described as the fraction of the bulk (or total) rock volume which contains the trapped phase. It is given by $\phi S_{(nw)r}$, where ϕ is the porosity of the rock and $S_{(nw)r}$ is the residual saturation of the non-wetting phase. Thus, the volume of CO₂ stored by residual trapping can be obtained by multiplying the bulk volume of the storage formation by the capillary trapping capacity measured from experiment. Figure 1 displays the capillary trapping of CO₂ in the pores of the reservoir rock.

Numerous research works have been proposed to understand the ongoing physical and chemical changes occurring within the underground formation. Examples of these

Fig. 1 CO₂ trapping by capillary trapping mechanism

changes include dissolution, chemical reactions, convective mixing, advective processes, and dispersion. These processes result from the trapping of CO₂ below the reservoir traprocks and its resulting decrease in the brine pH.

This article attempts to address a gap in the literature by providing a review of both the experimental and modeling approaches in CO₂ underground sequestration. Therefore, the key objective of this research article is to provide insights into the current trends of various experimental and modeling approaches while also documenting past and current practice regarding the storage of CO₂. Furthermore, this research output will be useful for researchers and organizations intending to carry out CO₂ sequestration operations.

Guidelines for CO₂ sequestration operation

Shafeen et al. (2004) suggested the injection of CO₂ into a porous and permeable reservoir covered with a caprock located at least 800 m beneath the earth's surface where CO₂ can be stored under supercritical conditions. They proposed that the injection pressure and temperature should be above the critical pressure and temperature of CO₂. They introduced the first study of its kind in Ontario and noted that the methodology would reduce the total CO₂ emission. They concluded that establishing adequate safety measures and implementing a contingency plan in case of a blowout of an injection well could be some of the necessary preconditions for sequestration.

The geological formation and lithology play an important part in the success of a CO₂ sequestration project. Wellman et al. (2003) studied the interaction between the CO₂-brine mixtures with the reservoir rocks. In developing their model, the authors carried a numerical simulation of this interaction using a tool called TRANSTOUGH. Based on their

findings, the authors observed a strong dependency between the lithology and the amount of CO₂ that was injected in the rocks. Factors such as heterogeneity and connectivity of the geological formation result in varying levels of CO₂ flow behavior (Soltanian et al. 2016a, b, 2018a, b; Trevisan et al. 2017). Fluvial sedimentary deposits exhibit a characteristically high level of connectivity and discontinuities. Additionally, viscous, capillary, and gravity forces influence the flow of CO₂ in all underground formations (Delshad et al. 2013). This interplay between the three forces occur at different phases. For example, in a system undergoing CO₂ injection at high injection flow gradient, the viscous effect acts as the driving force on the formation of brine. The effects of gravity and capillarity start after the completion of the injection with a resultant impact on fluid separation and gas trapping.

Friedmann (2007) came up with an idea that serves as the key mode for reducing greenhouse gas emissions. He proposed that to reduce GHGs, the CO₂ must be separated from the parent fossil fuels and injected from a large point source into the underground. He stated that the widespread usage of the sequestration process will need a deep understanding of processes involved in the trapping of CO₂ underground and also, the need to provide sophisticated methods for monitoring the injection.

Cooper (2009), as part of the CO₂ capture project, underlined four distinct phases of CO₂ sequestration:

- Site selection and development (3–10 years): During this phase, the site of sequestration is identified.
- Operation (> 10 years): The phase when CO₂ is injected into the subsurface.
- Closure: The phase during which the injection wells are plugged and the reservoirs are monitored to ensure successful implementation of the sequestration project.
- Post Closure: During this phase, the permanence of the CO₂ reservoir is established.

The author also established that three elements are essential for a feasible geological storage: sufficient pore volume to store the gas, sealing layer to ensure containment, and high injectivity is necessary (high permeability, > 100 mD).

Cherepovitsyn and Ilinova (2016) outlined the main approaches to the implementation of CO₂ sequestration technologies in the oil and gas industry in Russia, and also identified the ecological, economic, and social issues of their usage. They indicated that promotion of the technology of CO₂ sequestration by means of capturing and injecting it into underground reservoirs is a promising mechanism of reducing the CO₂ concentration. In addition, they mentioned that CO₂ capture and storage (CCS) technologies might be used to enhance oil recovery (EOR-CO₂) and production by oil extraction and decreasing oil viscosity. They presented some conceptual view

of the potentially sustainable implementation of EOR-CO₂ technologies within the context of the oil and gas industry.

Determination of the CO₂ storage capacity

Understanding the storage capacity of any proposed CO₂ storage medium is a key stage during consideration. Recent methods used in previous applications have focused on the use of the effective pore volume available in the mass balance approach and limited to open formations. Most storage systems are composed of compartmentalized reservoir systems with characteristically low permeability regions. Not all systems are open; recent studies by Muggeridge et al. (2004) and Puckette et al. (2003) reported the existence of reservoirs with no communication with the adjoining formations, i.e., closed system. Zhou et al. (2008) proposed a numerical method to estimate the storage capacity of both closed and semi-closed systems. In developing their model, the authors used the TOUGH2/ECO2N simulator and proposed a model based on the assumption that the amount of injected CO₂ will result in a pressure build-up and that the CO₂ displaces an equivalent amount of reservoir formation fluid. The proposed model is based on Eq. (1), as follows:

$$V_{\text{co}_2}(t_1) = (\beta_p + \beta_w) \times V_f \times \Delta p(t_1) \quad (1)$$

where $V_{\text{co}_2}(t_1)$ is the pore volume (PV) of the injected CO₂ at injection time (t_1), $\Delta p(t_1)$ is the average pressure build up at t_1 , β_p and β_w represent the pore and brine compressibility and V_f is the initial PV of the formation.

Additionally, Zhang et al. (2011) proposed another method to estimate the CO₂ storage capacity of oil reservoirs. They assumed the existence of a non-interacting reservoir system and that the CO₂ storage can be calculated independently for the different trapping mechanisms. Zhang et al. proposed a model that encompasses the amount of CO₂ in the oil zone ($V_{\text{co}_2\text{-in-oil}}$) and water zone ($V_{\text{co}_2\text{-in-aquifer}}$) as shown in Eq. (2):

$$V_{\text{co}_2} = V_{\text{co}_2\text{-in-oil}} + V_{\text{co}_2\text{-in-aquifer}} \quad (2)$$

$$V_{\text{co}_2\text{-in-oil}} = \rho_{\text{cor}} \times \left[\frac{(R_f + R_{\text{EOR}}) \times \text{OOIP} \times B_o}{\rho_{\text{os}} + (V_{\text{pw}} - V_{\text{iw}}) \times B_w} \right] + (\text{OWIP} + V_{\text{iw}} - V_{\text{pw}}) \times R_w^{\text{co}_2} + (1 - R_f - R_{\text{EOR}}) \times \frac{\text{OOIP}}{\rho_{\text{os}} \times R_o^{\text{co}_2}} \quad (3)$$

$$V_{\text{co}_2\text{-in-aquifer}} = A \times D \times \phi \left\{ a \times S_g^{\text{struc}} \times \rho_{\text{coa}} + b \times (1 - S_g^{\text{struc}}) \times \rho_{\text{coa}} + \left[a \times (1 - S_g^{\text{struc}}) + b \times (1 - S_g^{\text{resid}}) + (1 - a - b) \right] \times R_w^{\text{co}_2} \right\} \quad (4)$$

where ρ_{cor} is the density of CO_2 at the reservoir condition; ρ_{coa} is the density of CO_2 in the water zone; ρ_{os} is the surface density of the oil, OOIP is the oil initially in place; B_o is the oil formation volume factor; B_w is the water formation volume factor; V_{pw} is the total amount of produced water at the surface, V_{iw} is the amount of injected or invaded water at the surface; $R_o^{\text{co}_2}$ and $R_w^{\text{co}_2}$ represents the solubility of CO_2 in residual oil and water, respectively; R_f and R_{EOR} are the recovery factor of water flooding and CO_2 injection, respectively; ϕ , A , and D represent the porosity, area, and thickness of the associated water zone, respectively; S_g^{struc} and S_g^{resid} are the saturation of CO_2 in the trapping structure and residual CO_2 in the associated aquifer, respectively; and a and b are the volume fractions of the structure and residual gas trapping zone of the associated water zone, respectively.

Okwen et al. (2010) proposed a conceptual model to estimate the storage efficiency of saline aquifers. The authors assumed the presence of an inert porous medium, constant temperature, constant fluid density and viscosities over time and space, existence of high temperature CO_2 , immiscible fluid (CO_2 + brine) phase, infinitely large radial aquifer system with small thickness, predominantly horizontal flow, and constant injection rate of CO_2 . They proposed two numerical models given by the equation below that relates the storage efficiency of a saline aquifer (ϵ) to the residual saturation, CO_2 -Brine mobility ratio, and dimensionless constant.

$$\Gamma = \frac{2\pi\Delta\rho k\lambda_b B^2}{Q_{\text{well}}} \quad (5)$$

$$\text{If } 0 \leq \Gamma \leq 0.5,$$

$$\epsilon \approx (1 - S_r) \frac{1}{\lambda} \quad (6)$$

$$\text{If } 0.5 \leq \Gamma \leq 50,$$

$$\epsilon \approx \frac{2(1 - S_r)}{(0.0324\lambda - 0.0952)\Gamma + (0.1778\lambda + 5.9682)\Gamma^{0.5} + 1.6962\lambda - 3.0472} \quad (7)$$

where Γ is the dimensionless number, λ is the ratio of the mobility of CO_2 to brine, $\Delta\rho$ is the difference between the brine and CO_2 density, g is the gravitational acceleration, λ_b is the mobility of brine, and k is the absolute permeability of the geologic formation.

It is worth mentioning that there exist several methods to estimate the storage capacity of the different geological storage systems. Additionally, the accuracy of these models depends upon the type of storage system, level of certainty in the data and, availability of information required to accurately estimate the storage capacity of the formation (Kopp et al. 2009). To account for the uncertain nature of reservoir systems, Kopp et al. (2009) proposed

Fig. 2 Field location (Pham et al. 2011)

a model that assumes the storage capacity of the geologic formation is given by the mass of CO_2 that would result in leakage. Equation (8) gives the model by Kopp et al. (2009) that relates the effective mass of stored CO_2 (M_{eff}) to the average porosity (ϕ), density of CO_2 (ρ_{co_2}) at particular temperature (T) and pressure (p), and the total reservoir volume (V_{tot}).

$$M_{\text{eff}} = \phi \times C_h \times (C_{\text{ig}} C_{\text{gg}} + C_{\text{il}} C_{\text{gl}}) \times V_{\text{tot}} \times \rho_{\text{co}_2}(T, p) \quad (8)$$

where C_h , C_{ig} , C_{gg} , C_{il} , and C_{gl} represents the heterogeneous capacity coefficient, intrinsic capacity occupied by the gas phase, intrinsic capacity coefficient occupied by the liquid phase, geometric capacity for the liquid, and geometric capacity of gas phase, respectively.

In other related studies, Pham et al. (2011) developed a numerical model to estimate the amount of CO_2 that was

proposed to be injected into the Tubåen formation from the Snøhvit field, Barents Sea (Fig. 2).

The injected CO_2 increases the reservoir pressure and it is, therefore, necessary to monitor the increase in pressure such that it does not exceed the fracture pressure which in turn would lead to formation failure. The authors evaluated whether porosity can be considered as a factor in selecting a candidate reservoir/aquifer for CO_2 sequestration. The logging tools proposed that the porosity of the formation might be a good indicator in deciding a candidate for CO_2 injection. Klara et al. (2003) conducted an integrated collaborative technology program for CO_2 sequestration in a geologic formation. The main objective

was to predict the stored volume of CO₂ left in the formation since the remaining amount contributed toward global warming. They studied and proposed a flowchart for better accentuation.

Economides and Economides (2010) proposed a model based on material balance to report on the failure of sequestration in addressing the necessity of storing CO₂ in a closed system. Their calculations suggest that the volume of the liquid or supercritical CO₂ to be disposed cannot exceed 1% of the pore volume. Thus, this will require 5 to 20 times more underground reservoir volume than has been envisioned by other studies, rendering geologic sequestration of CO₂ a profoundly non-feasible option for the management of CO₂ emissions. The results of the material balance modeling showed that the quantity of CO₂ injected in the liquid stage (larger mass) obeys an analogue of the single phase, liquid material balance, long-established in the petroleum industry for forecasting undersaturated oil recovery. They indicated that the total volume that can be stored is a function of the initial reservoir pressure, the fracturing pressure of the formation of an adjoining layer, and the CO₂ and water compressibility and mobility values.

Experimental approach

This section of the review analyzes the experimental studies of CO₂ sequestration in different underground formations such as; saline aquifers (Cinar et al. 2007; Izgec et al. 2005; Jeddizahed and Rostami 2016; Liu and Maroto-Valer 2011; Mohamed and Nasr-El-Din 2013; Oloruntobi and LaForce 2009; Taheri et al. 2012), shales (Jin et al. 2017), deep coal seams (Prusty 2008; Wang et al. 2016), and depleted gas reservoirs (Luc et al. 2004). The studies are also aimed at determining the amount of injected CO₂ that can be stored as an immobile phase at the pore scale.

Jin et al. (2017) conducted an experimental study on Bakken shales to analyze CO₂ EOR and its storage in unconventional oil formations. CO₂ adsorption isotherm indicated that substantial amount of CO₂ can be trapped (~ 17 mg/g) in the Bakken shale for a broad pressure range (0–40 MPa).

Prusty (2008) performed an experimental study on coal samples from three coal seams to investigate the potential of sequestration and enhanced gas recovery (EGR). The results of this research advised that the sorption behavior could not be generalized for different types of coals. This was because of different sorption behavior showed by those studied coal samples. Wang et al., (2016) studied the interaction of CO₂ with rock and brine in deep coal seams. The interaction of calcareous mudstone with CO₂/brine results in the changes of mineralogy which improves the CO₂ sequestration capacity of deep coal seams.

Luc et al. (2004) performed several experimental studies on understanding the sequestration of supercritical CO₂ in carbonate core samples obtained from depleted gas reservoirs. The core porosity and fluid saturation were evaluated using an X-ray CT scanner. The study revealed that longitudinal dispersion coefficient of CO₂ under isothermal conditions reduces with rising pressure and increases with temperature under isobaric conditions.

A vast amount of literature is available for CO₂ sequestration in saline aquifers. Jeddizahed and Rostami (2016) conducted an experimental study on the precipitation of salt due to the interaction between CO₂ and the aquifer surface during sequestration. It was concluded that the amount of salt precipitation increases with salinity and reduces with the injection rate. A comprehensive review was conducted to show the parameters influencing mineral trapping of CO₂ sequestration in brines which includes, pressure, temperature, pH of brine and composition of brine (Liu and Maroto-Valer 2011). Brine pH was found to be the most dominant parameter as a high value of pH (> 9) supports precipitation of carbonate minerals. Cinar et al. (2007) investigated the effects of viscous, gravitational, and capillary factors in the CO₂ injection. Experiments were conducted in glass containing bead packs which helped in determining the regimes of pore scale instability. Izgec et al. (2005) performed an experimental study using computerized tomography (CT) for the capacity of sequestration in a carbonate aquifer. Alteration in permeability for varying injection rates of CO₂, pressure, and temperature at various salt concentrations were presented. CO₂ sequestration by mineral trapping was found to be smaller than solubility trapping in that study. Oloruntobi and LaForce (2009) analyzed the impact of aquifer heterogeneity on CO₂ sequestration using experimental studies, which shows that trapping is greatly influenced by heterogeneity. The results show that poorly consolidated sands trapped less air than well consolidated sands. Sequestration of CO₂ into brines leads to a higher mixture density. The impact of convection due to density on the dissolution rate was investigated experimentally (Taheri et al. 2012). Authors also compared the results with simulation studies. Interaction of CO₂ with rock and brine during CO₂ injection into carbonates results in precipitation which dampens the well injectivity. Experimental studies were conducted to investigate the permeability loss using core floods (Mohamed and Nasr-El-Din 2013). Large amount of damage was seen in more heterogenous cores. Precipitates reduces the permeability of cores with high permeability, while CO₂-brine capillary forces enhance the permeability reduction for the low permeability cores. Table 1 lists the key finding of experimental studies on Carbon dioxide sequestration.

Table 1 Key findings of experimental studies on CO₂ sequestration

References (Author, Year)	Formation/source type	Study aim	Key findings
Jin et al. (2017)	Shales	Experimental study on Bakken shales to analyze CO ₂ EOR and its storage	CO ₂ adsorption isotherm suggested that considerable amount of CO ₂ could be trapped in the Bakken shale for a broad range of pressure
Prusty (2008)	Coal	Investigation of the potential of sequestration and enhanced gas recovery (EGR)	Coal's preferential sorption behavior could not be generalized for different types of coals
Wang et al. (2016)	Coal	To study the interaction of CO ₂ with rock and brine in the CO ₂ sequestration process for deep coal seams	Changes of mineralogy helps in improving the CO ₂ sequestration security in the deep coal seam
Luc et al. (2004)	Depleted reservoirs	Study of supercritical CO ₂ sequestration in core samples from depleted gas reservoirs	Longitudinal dispersion coefficient of CO ₂ reduces with rising pressure keeping temperature constant, and that of rises with rising temperature keeping pressure constant
Jeddizahed and Rostami (2016)	Saline aquifer	A study on precipitation of salt occur due to interaction between CO ₂ and saline aquifers during sequestration	The degree of salt precipitation rises with salinity and falls with the injection rate for specific ranges of permeability reduction
Liu and Maroto-Valer (2011)	Saline aquifer	A review on parameters influencing mineral trapping of CO ₂ sequestration in brines	The most effecting parameter among them is brine pH because over a pH of nine supports carbonate minerals' precipitation
Cinar et al. (2007)	Saline aquifer	To investigate the effects of viscous, gravitational, and capillary factors in the CO ₂ injection	Regimes of pore scale instability were found in the existence of non-favorable density and viscosity gradients. This could not be modelled by the aid of traditional methods
Izgec et al. (2005)	Saline aquifer	Capacity of sequestration in a carbonate aquifer was studied	There is a rise then fall of permeability for vertical cores with high injection rates. Horizontally aligned cores showed reduction of permeability because of formation of calcium carbonate precipitates. CO ₂ sequestration by mineral trapping is found to be smaller than solubility trapping
Oloruntobi and LaForce (2009)	Saline aquifer	Influence of aquifer heterogeneity on CO ₂ sequestration	Poorly consolidated sands trapped less air than well consolidated sands
Mohamed and Nasr-El-Din (2013)	Saline aquifer	Interaction of fluid and rock during CO ₂ sequestration. Analysis of permeability loss during this process was studied	CO ₂ -brine capillary forces enhance the permeability reduction for the low permeability cores. On the other hand, precipitates formed cause damage for cores with high permeability

Numerical modeling and simulation of CO₂ sequestration

A considerable amount of research has been conducted in simulating and modeling CO₂ sequestration in the subsurface. Calabrese et al. (2005) studied the physical and chemical processes during CO₂ sequestration in a depleted gas reservoir located in the north of Italy. They concluded that to maximize the volume of CO₂ injected, an optimum rate has to be defined. At higher rates, the gas channels through high permeability streaks, and hence the storage capacity is reduced. While at lower rates, the denser CO₂ falls to the bottom of the gas zone and dissolves in the aquifer. They also concluded that molecular diffusion, dispersion, and geochemistry were not important factors for assessing the CO₂ storage.

Seo and Mamora (2005) performed experimental and simulation studies to evaluate the feasibility of sequestering supercritical CO₂ in depleted gas reservoirs. They performed experimental studies to obtain relative permeability curves; then, 3D simulation models of one-eighth of a five-spot pattern were used to evaluate the injection of CO₂.

Hesse (2008) presented a compact multiscale finite volume (CMSFV) method for the numerical simulation of CO₂ storage in large-scale heterogeneous formations. The authors identified that dissolution is an important trapping process if CO₂ is present in a structural trap. They also concluded that high permeability aquifers favor dissolution trapping. The authors indicated that high permeability, gently dipping, and deep saline aquifers are the optimal targets for CO₂ sequestration.

Momeni et al. (2012) presented a simulation study using ECLIPSE E300 (compositional simulation model) of a synthetic geologic model used to sequester CO₂. They concluded that the operating expenditure for sequestration in a depleted oil reservoir is less than in an aquifer because of lower well corrosion during injection. This is due to the higher brine concentration in an aquifer which increases the probability of corrosion.

There is a lack of understanding of the detailed mechanism of subsurface sequestration. This is due to the lack of information regarding the heterogeneity and the geometry of the reservoir/aquifer selected for sequestration. The success of sequestration depends on the injection rate, injection pressure, injection strategy, and the type and orientation of the injection well. Zhang and Agarwal (2012) performed an optimization based on genetic algorithms to optimize the sequestration operation. They used the TOUGH2 solver developed by the US Department of Energy. They used both horizontal and vertical wells. Based on the results of the optimization, they concluded that the horizontal wells were much better when compared to vertical wells in aspects such

as reduced migration and pressure build-up which could contribute to cap rock fracture and gas leakage.

Bao et al. (2016) performed a large-scale CO₂ sequestration by coupling reservoir simulation with molecular dynamics (MD). The simulation was performed on massively parallel high-performance computing systems. They believed the coupling of molecular dynamics would provide better predictability of fluid properties under varying geological conditions. In their flow equations, they assumed the flow to be incompressible and used Darcy's equation to model the velocity in the reservoir. The advection diffusion equation was used to model the transport of CO₂ in the porous media. In the MD simulation, they solved Newton's equation of motion and the Leonard Jones and Coulomb interactions were used to represent the interaction between two atoms.

Hao et al. (2016) developed a methodology to combine reservoir simulation, rock physics theory, and seismic modeling to simulate and monitor a sequestration process in an idealized geological model located in the Sleipner field. They modelled CO₂ injection using the two-phase flow model and solved the equations using the IMPES method. Then, they analyzed the effects of fluid saturation and pressure change on the elastic wave velocity based on the Gassman equation, Hertz–Mindlin theory, and effective fluid theory. Finally, seismic modeling was performed using P-wave potential equations and the symplectic stereomodeling (SSM) method on the transformed geologic model obtained from reservoir simulation.

Foroozesh et al. (2018) performed a field scale simulation of an aquifer consisting of one well injecting CO₂ for ten years. The model was run for 100 years with the results showing that CO₂ solubility trapping was the main mechanism of sequestration. The simulation was performed using CMG-GEM. The results demonstrated that good vertical permeability and lower injection pressures are important factors in reducing leakage.

Mkema and Bin (2019) investigated the optimal injection strategy to enhance CO₂ storage. Their results concluded that an optimum injection pressure needs to be maintained as the pressure build-up created by injection may fracture the cap rock, which would then lead to CO₂ leakage. The authors highlighted that an optimum CO₂ sequestration does not lead to excessive migration of the injected gas. Table 2 summarizes a few of the latest additions in modeling and simulation studies on CO₂ sequestration.

Effects of CO₂ sequestration

This section outlines the direct impacts of CO₂ sequestration on its surroundings.

Table 2 Summary of recent developments in modeling and simulation of CO₂ sequestration

References (Author, Year)	Study aim	Summary
Ajayi et al. (2019)	Assessed the possibility of CO ₂ storage in selected aquifers in Emirates of Abu Dhabi	Storage capacity of the aquifer could be improved by fracturing a portion of the aquifer and removal of in-situ brine from the aquifer Also, extent of trapping by the aquifer's storage mechanism defines the CO ₂ plume speed Simsima, Dammam, UER and Shuaiba are favorable candidate for CO ₂ storage Trapping capacity is dependent on relative permeability curve, salinity and hysteresis
Mkema and Gong (2020)	By applying numerical simulation approach, they studied the long-term CO ₂ storage potential of Liaohu Basin, China in terms of storage capacity and trapping mechanism	CO ₂ storage is stored in three forms, namely supercritical phase, trapped (or residual), and dissolved CO ₂ Changes in water saturation (Sw) results in variation in CO ₂ storage capacity and better storage capacity at lower water saturation than high; higher Sw lead to reduction in available pore space for injected CO ₂ plume Injection rates decreases as shut-in period approaches due to the replacement of available pore spaces by CO ₂ plume and increased injection pressure. Increasing Kv/Kh ratio leads to increased CO ₂ storage capacity. Also, increasing the salinity leads reduction in quantity of CO ₂ dissolved in brine. Amount of dissolved CO ₂ decreases with reduction in bottomhole pressure (BHP)
Ampomah et al. (2016)	They studied the dependence of CO ₂ storage capacity on trapping mechanism (such as structural-stratigraphic, solubility, and residual trapping) and also, the effects of the WAG cycle, hysteresis and salinity on CO ₂ storage	Dissolution of CO ₂ in oil is the predominant trapping mechanism. If hysteresis is present, residual trapping can exist as a competing trapping mechanism An increase in amount of supercritical CO ₂ could occur due to reduction of reservoir pressure below the MMP. Increased gas (not water) cycle, Gas recycling, reduction of amount purchased CO ₂ and addition of wells/patterns leads to high oil recovery and CO ₂ storage Determination of optimal WAG cycles is required to lower viscous fingering which inhibit CO ₂ mobility. At reduced salinity, CO ₂ dissolution could increase. To ensure the development of accurate reservoir models, modeling of hysteresis should be accounted if present
Zhang et al. (2019)	They studied the thermodynamic phase behavior and strategies for CO ₂ storage in fractured nanopores	To obtain an optimal performance for CO ₂ storage in deep shale formations, purified CO ₂ plume, low temperatures and large pore radii should be considered
(Soltanian et al. 2016a, b)	Authors explored the application of high resolution static model in CO ₂ injection study. Also, they conducted sensitivity studies of parameters affecting movement of CO ₂ plume	Accurate representation of the formation heterogeneity is an important factor for any carbon sequestration project Presence of highly permeable pathways (from fluvial deposits) has a strong effect on CO ₂ transport For short-time experiment and long injection rate, pressure response is highly correlated to relative permeability, and diffusion plus capillarity are have less effect on CO ₂ plume due to high injection rates and dominant advective forces. Reduced spreading of CO ₂ plume and increased pressure build up occurs due to low gas relative permeability

Table 2 (continued)

References (Author, Year)	Study aim	Summary
Hosseininoosheri et al. (2018)	They studied the synergistic effect of trapping mechanism on partitioning of CO ₂ in a three phase fluid (oil, gas and brine). Also, the effect of field development strategies on CO ₂ utilization was studied	As a deviation from the general believe that the dominant trapping mechanism is the structural trapping during early and late time injection of CO ₂ , the authors discovered that solubility of CO ₂ in oil is also highly important. Development strategies play an important role on the contribution of the various trapping mechanism Water alternating gas (WAG) injection improve the storage integrity by decreasing the amount of mobile CO ₂ and increasing miscible/dissolved CO ₂ . Higher vertical displacement of mobile CO ₂ will lead to CO ₂ leakage Both physical and chemical properties are the dominant factors during CO ₂ transport. As a result, small changes in reservoir rock properties have significant effect on CO ₂ transport There exist an increase in concentration of dissolved CO ₂ (results in pH drop) and occurrence of geochemical reactions (e.g. mineral dissolution) within the nanopores of fluvial channels If interested in predicting the storage capacity during CO ₂ sequestration, due consideration should be accorded to the choice of relative permeability model and effect of hysteresis. During the early CO ₂ -EOR injection, the three phase model has small effects on CO ₂ trapping during CO ₂ -EOR injection and becomes higher during post CO ₂ -EOR injection As a result of heterogeneity, incorporating a WAG process may lead to increased impact of the three phase relative permeability model
Soltanian et al. (2019)	By incorporating chemical reaction, the authors developed geochemical model to study the multiphase flow of CO ₂ -brine within geologic formation	
Jia et al. (2018)	In this study, the authors explored the relations between the three phase relative permeability and trapping mechanism	
Yang et al. (2020)	Authors studied the dependence of the flow behavior and capillary trapping on heterogeneity	Heterogeneity of the reservoir pore structure has a strong effect on the spreading and trapping of the CO ₂ plume At the end of primary drainage, decreasing the sandstone proportion results in a reduction in the amount of residual CO ₂ trapped Choice of trapping models and heterogeneity may lead to increased uncertainty in residual trapping of CO ₂ At higher formation salinity, they observed an increase in CO ₂ dissolution in oleic phase compared to the aqueous phase Existence of strong relation between the fluid saturation and CO ₂ solubility. At higher water saturation region, CO ₂ gas dissolve preferentially in aqueous phase For long-term storage process, due consideration should be accorded to geochemical effects compared to mineral trapping effects with a characteristic lesser impact
Sun et al. (2020)	Authors made attempts to evaluate the various CO ₂ sequestration mechanisms present in a sandstone unit	Strength and rate of leakage has strong dependence on the plug gap aperture If the well location is not known, thermal monitoring at the ground surface could be used to monitor leakage Onset of pressure within the well could be used to identify CO ₂ leakage. At the onset of leakage, there exist an increase in well top pressure and significant decrease in plug top pressure
Pan and Oldenburg (2020)	They studied the dynamics and characteristic signals depicting with onset of CO ₂ leakage	

Table 2 (continued)

References (Author, Year)	Study aim	Summary
Arif et al. (2016)	They studied the dependence of wettability of solid surfaces (quartz, mica and coals) on pressure, temperature and salinity	Neumann's equation of state is an effective method for quantifying interfacial phenomenon as a function of pressure, temperature and salinity For the surface with CO ₂ and any solid material, the interfacial energy (or interfacial tension) increases with temperature but decreases with pressure. As a result of higher hydrophobicity, an oil-wet mica surface exhibits the lowest interfacial energy in comparison to other solid/CO ₂ surfaces For any water–solid (except quartz), interfacial energy decreases with temperature and exhibit an opposite effect with quartz surface. Increasing the salinity results in increased interfacial tension of solid/water surface

Effect due to chemical reactions

Soltanian et al. (2019) performed a field scale simulation of the injection of CO₂ in an aquifer saturated with brine using a compositional model. Additionally, the authors investigated the effects of geochemical reactions on the pressure response and breakthrough times of the reservoir. The authors observed the time-dependent behavior of the pH and mineral changes of the aquifer located in a fluvial environment. The bottom-hole flowing pressure profile did not exhibit significant differences when compared with the observations from reactive transport simulations by Hosseini et al. (2013). For a system with weak reactivity, the effects of including capillary and compositional reactions were negligible and the difference between the BHP for both these cases was insignificant. Small variations in petrophysical properties can significantly affect the migration of CO₂ with regards to the breakthrough times.

Effect of adsorption

Viète and Ranjith (2006) performed a study to explore the effects of the adsorption of CO₂ on the compressive strength and permeability of Southeast Australian brown coal. The results of the study showed a noticeable compressive strength decrease. However, further testing is required to reveal the reason for the apparent negligible strength reduction with CO₂ adsorption at higher confinement. The authors conducted CO₂ outflow measurements during the stress–strain process, and demonstrated an initial permeability decrease with pore closure, followed by a significant increase in permeability with fracturing. They indicated that when dealing with coal seam CO₂ sequestration, it is important to consider the effect of the localized in-situ stresses and whether they are sufficient to initiate fracturing due to adsorptive weakening. Lastly, they mentioned that coal properties (e.g., rank, moisture content) are likely to affect the geo-mechanical influence of CO₂ adsorption, and discussed the expected magnitude of the proposed fracture related to permeability increase.

Effects of capillarity, hysteresis, and wettability

In microscopic pore spaces, capillary pressure has a strong effect on flow (Delshad et al. 2013). During CO₂ storage, the capillary effect becomes important due to the hysteresis effect. In a previous study by Hebach et al. (2002), the interfacial tension between the brine and supercritical CO₂ has been observed to have a direct relationship with temperature and salinity and an inverse relationship with pressure. Delshad et al. (2013) proposed a numerical method to study the impact of trapping and hysteresis on CO₂ storage using the Cranfield field data. In systems with trapping but no

capillary hysteresis, the author observed an upward movement of the CO₂ relative permeability curve and a reduced residual CO₂ saturation and bottom-hole pressure of the injection well. Additionally, a reduced CO₂ migration exists when the residual gas saturation increases, demonstrating the effect of hysteresis on CO₂.

Iglauer et al. (2015) reviewed published studies on the effects of CO₂ wettability in storage and seal rocks. They introduced the wettability concept and explained its importance in geo-sequestration (CGS) projects. In addition, they showed a dramatic impact caused by wettability during structural and residual trapping of CO₂. They concluded with a few discoveries about sandstone and limestone, in addition to pure minerals; for example, quartz, calcite, feldspar, and

mica are unequivocally water wet in a CO₂–water system, while oil-wet limestone and oil-wet quartz or coal exhibit intermediate wettability in a CO₂–water framework. Based on their findings, the authors opined that the contact angle alone is insufficient to predict capillary pressures in either reservoir or seal rocks. Their findings are shown in Figs. 3, 4, and 5.

Kim et al. (2013) developed a model to measure the thicknesses of KCSI₂ brine films on two different roughness mica surfaces under conditions representative of geological CO₂ sequestration (7.8 MPa and 40 °C) to understand the influences of mineral surface roughness and capillary potential. The measured brine thicknesses on the Mica 1 (smooth) and Mica 2 (rough) surfaces were 23–8 nm and 491–412 nm, respectively.

Fig. 3 Molecular dynamics simulation for the determination of water contact angles on quartz and b-cristobalite surfaces (Iglauer et al. 2015)

Fig. 4 Capillary pressure (P_c)-water saturation (S_w) profiles for **a** a strong water-wet system, **b** intermediate-wet system, and **c** CO_2 -wet system (Iglauer et al. 2015)

Fig. 5 Residual saturation profiles at initial conditions based on **a** pore-network modeling and **b** laboratory measurements. (Iglauer et al. 2015)

Fig. 6 Comparisons between brine film drainage and rewetting measurements at different capillary potentials of model predictions for adsorbed film thicknesses (Kim et al. 2013)

They noticed that within the small range of tested capillary potentials (0.18–3.7 kPa), brine film thicknesses on mica were governed by surface roughness and only weakly influenced by capillary potentials. They compared drainage and rewetting isotherms, and observed film thickness hysteresis that is indicative of changes in mica wettability; see Fig. 6.

Challenges associated with CO₂ sequestration

Several challenges are associated with the implementation of a CO₂ sequestration project. It is difficult to list all the challenges as part of this review. Thus, the problems associated with the injection of CO₂ are considered. Pipelines are the most commonly used methods for the transport of high volumes of CO₂ over long distances (Leung et al. 2014). One of the major issues associated with the injection of CO₂ is the acidic nature of the gas, which may lead to corrosion of the pipelines. Another issue with CO₂ injection is that CO₂ can cause significant asphaltene deposition, which may lead

to the plugging of the reservoir/aquifer and the blocking of the transportation pipeline (Zanganeh et al. 2012).

Problems associated with the corrosive nature of CO₂

The chemical reaction of CO₂ with water forms carbonic acid; this acid lowers the pH of the aqueous phase, resulting in severe internal corrosion of the pipes. The carbonic acid attacks the iron to form soluble iron bicarbonate, which upon heating releases CO₂ and an insoluble iron carbonate or hydrolyzes to iron oxide. If H₂S is present, it will react with the iron oxide to form iron sulfide. High liquid velocities can erode the protective iron sulfide film with resulting higher corrosion rates. Increased corrosion leads to severe pitting attack, which is one of the predominant causes of pipeline failures.

It is, therefore, important that an effective pipeline management program is carried out to minimize the risks and consequential health, environmental, and economic impact of corroded pipeline failures. Moloney et al. (2008) explained the corrosion effects on the gas hydrates and how

to control it due to wet sour gas transmission systems. To prevent corrosion and corresponding operational issues associated with the presence of water in the CO₂ stream, corrosion inhibitors should be added to help protect carbon steel pipelines from metal degradation. In addition, the corrosion inhibitor should be compatible with the system.

Loizzo (2008) observed the effects of CO₂ injection on cementation. The evaluation was performed precisely and clearly demonstrated that cement and steel can be corroded by CO₂ which will be accelerated in the case of bad cement jobs. A good planning and execution for cementing a well was conducted where a centralizer was used for each joint of casing. This is not widespread practice, especially for vertical wells. The plan was to ensure good isolation for CO₂ operations. However, the hole was not perfectly vertical; deviations < 2° mandated the use of squeeze cements prior the CO₂ injection.

Nelson et al. (1990) indicated that CO₂-laden waters can destroy the structural integrity of set Portland cements. The chemistry of this reaction is as follows:

In the first reaction, approximately 1% of the dissolved CO₂ reacts with water to form carbonic acid. As the CO₂-laden water diffuses into the cement matrix, the dissociated acid is free to react with the free calcium hydroxide (reaction 2) and the C–S–H phase (reaction 3). As CO₂-laden water continues to invade the matrix, another equilibrium is established.

In the presence of excess CO₂ (reaction 4), calcium carbonate is converted to water soluble calcium bicarbonate, which can migrate out of the cement matrix. In reaction 5, the dissolved calcium bicarbonate can react with calcium hydroxide, forming calcium carbonate and water. The produced water can then dissolve more calcium bicarbonate. The net result is a leaching of cementitious material from the cement matrix, an increase in porosity and permeability, and a decrease of compressive strength. Downhole, this means loss of casing protection and zonal isolation. CO₂ corrosion of Portland cements is thermodynamically favored and cannot be prevented, although it may be mitigated by the use of synthetic cement, which is

expensive and may not be feasible for most CO₂ flooding or CO₂ sequestration projects. Instead, it is more practical to lower the degradation rate of Portland cement systems.

Le Guen et al. (2008) indicated that CO₂ injection can create preferential channels over time, allowing migration of CO₂ from the reservoir to shallower formations, for example, in aquifers and/or to the surface. Possible local impacts resulting from injection operations or leakage could be:

- Acidification of potable aquifers, which can make water unsuitable for consumption.
- Acidification of soils with impact on vegetation or agriculture.
- Accumulations of gaseous CO₂ at the surface affecting human health and/or the environment.
- Increasing risks associated with CO₂ leakage over the storage period.

Nygaard et al. (2014) studied the effects of dynamic loading on wellbore leakage. They specified approximately 1000 wells in the Wabamun zone (near Wabamun Lake, Alberta, Canada) to determine the leakage pathway of CO₂. They observed that the main reason for this leakage was the well design, well scenario, and offset data of the area. They concluded that thermal and pressure change could lead to near wellbore stress reduction, which might lead to a change in the cement properties such as increased Young's modulus and Poisson's ratio, causing cementation design failures.

Asphaltene precipitation

CO₂ can be stored in high-viscosity and high-density hydrocarbon reservoirs where the oil cannot be easily recovered due to low mobility of the fluid (Alboudwarej et al. 2006; Cavallaro et al. 2008; Hascakir 2017). This, however, may lead to asphaltene dropout. Novosad et al. (1990) developed a model to predict the asphaltene deposition rate during CO₂ injection in a 29° API gravity reservoir. Their experimental results demonstrated that a considerable amount of solid deposit (consisting of Asphaltene, wax, and trapped oil) formed in the wellbore equipment and down hole facilities.

Kokal and Sayegh (1995) discussed the factors contributing to asphaltene precipitation, such as nature of rock and matrix, asphaltene and resin composition of the reservoir oil, formation brine and its composition, the nature of the injection gas, the presence of contaminants in the injection gas, temperature, and pressure conditions. They indicated that this problem can be best observed on the Weyburn reservoir and examined the effects of operating pressure, CO₂ concentration, brine formation, and contaminants in CO₂ such as methane and nitrogen on asphaltene flocculation/

precipitation. Weyburn is a light oil reservoir (28°–35° API gravity) located in south-eastern Saskatchewan. It is characterized by a higher permeability Vuggy zone at the bottom and a Marly zone at the top. The injected CO₂ is more likely to contact and mobilize the reservoir oil in the Marly zone, which could be the more susceptible area for asphaltene deposition.

Zanganeh et al. (2012) used a high-pressure cell and image processing techniques to visualize the asphaltene

deposition process and concluded that as the pressure increases, the area of deposition increases. They also concluded that an increase in temperature allows the asphaltene particles to flocculate and form larger particles.

Table 3 Worldwide CO₂ storage projects

Date	Name	Location	CO ₂ sequestration rate (1000 kg/year)
1996	Sleipner	Norway	1 million
2000	Weyburn	Canada	500,000+
2004	In Salah	Algeria	1.2 million
2007	Otway Basin	Australia	109,500 total
2007–2011	Snohvit	Norway	0.7 million
2018–present	Alberta Carbon Trunk Line	Canada	14.6 million
–	Boundary Dam	Canada	–
–	Cranfield	USA	–
2004–2006	Frio Brine	USA	–
2008–2009	Ketzin	Germany	67,271
2011	Citronelle	USA	–
2013	Northern Reef Trend	USA	–
2013	Port Arthur	USA	–
2006	Zama	Canada	–
2010–2014	Ordos	China	–

Fig. 7 Field sites focused on active or underway CO₂ storage projects (Sengul 2006)

Field studies

CO₂ storage can take place in a variety of subsurface reservoirs including but not limited to oil and gas reservoirs, aquifers, salt caverns, deep coal seams, deep ocean, and mineral carbonation (Voormeij et al. 2002; Shukla et al. 2010). Injecting CO₂ into hydrocarbon reservoirs may result in the added benefit of increasing oil production, which lies in the domain of Enhanced Oil Recovery (EOR). Thus, CO₂ EOR not only protects the environment but also improves oil recovery.

CO₂ storage in geological formations was first proposed in the 1970s (Holloway and Savage 1993) and practically implemented during the 1990s (Benson et al. 2006). There are several CO₂ storage projects in operation worldwide (Table 3). The active CO₂ storage projects are schematically presented in Fig. 7.

Sleipner Project

Sleipner is known as the first CO₂ sequestration project in the North Sea, as shown in Fig. 8. Inspired by the carbon tax policy of Norway, it started in 1996 and injected about 10 Mt of CO₂ by mid-2008 into the formation (Shukla

et al. 2010). The target formation is Utsira, comprising 200–300 m thick sandstone along with mudstone layers which are relatively thinner. The sandstone layer is a saline aquifer. There is a 200–300 m impermeable layer of cap-rock (shale) which prevents injected CO₂ from rising to the surface (Bachu 2000; Nooner et al. 2007; Lindeberg et al. 2001; Mackenzie et al. 2001).

Sleipner did not encounter major operational issues and is considered the most successful CO₂ sequestration project. Thus, CO₂ storage is considered feasible since significant problems did not arise in the carbon capture plant or injection wells (Korbøl and Kaddour 1995; Qi et al. 2009; Sengul 2006; Torp and Gale 2004; Yamamoto et al. 2004).

Weyburn Project

Another monumental project is the Weyburn Project situated in the Williston Basin in Saskatchewan, Canada. It started in 2000 and aimed to inject CO₂ into the oil fields for EOR. The Weyburn field is a Midale carbonate reservoir consisting of two different important units. The lower unit is known as Vuggy and the upper zone is named Marly. The Vuggy and Marly zones contain limestone and dolomite, respectively (Yamamoto 2004; Malik and Islam 2000). Further, the two

Fig. 8 CO₂ storage project of Sleipner in Norway (Sengul 2006)

zones are trapped by a caprock (anhydrite). Detailed characteristics of this field are provided by Burrowes (2001).

The Dakota Gasification Company provides CO₂ for injection into the Utsira formation at 3000–5000 t per day (Shukla et al. 2010). The estimated lifespan of this EOR project is 20–25 years, and it is predicted that by 2030, approximately 20 Mt of CO₂ will be deposited in the field (Bachu 2000).

In Salah Project

In 2004, British Petroleum (BP) and Statoil jointly started a CO₂ sequestration project. The project name is In Salah and is situated in Algeria. It is an operational gas field and sources CO₂ from the In Salah oil field (Ringrose et al. 2013). The CO₂ injected into the aquifer leads to a storage of 1.2 Mt per annum (Schaefer et al. 2000). The CO₂ is fed into the carboniferous sandstone formation which is 20 m in thickness located near the Krechba gas field. This field consists of 3 CO₂ gas injection wells and 4 gas production wells (Rutqvist et al. 2009). The total capacity of the formation is approximately 17 Mt of CO₂ (Mathieson et al. 2011). Between the period of 2004 and 2011, 4 Mt of CO₂ was injected into the Krechba formation (Mathieson et al. 2011, 2009; Rutqvist et al. 2009).

Advanced techniques like micro-seismic and time-lapse seismic data were utilized to monitor the project and to update the several models related to this project, which includes geomechanical, geological, and dynamic models. Because of the cap-rock integrity, the injection was suspended in mid-2011 (Pamukcu et al. 2011; Bhowmik et al. 2011). Migration of CO₂ from the reservoir to the overburden rock was undertaken, and importantly, leakage of CO₂ into the atmosphere did not occur during this transition (White et al. 2014). The In Salah project is instrumental in providing data on CO₂ injection in low permeability elastic reservoirs.

Snøhvit Project

The Norway based Snøhvit Project, started in 2007, is run by Statoil ASA and others (Negrescu 2007). It is known as the first offshore project where crude oil is extracted without using conventional offshore equipment. In the Snøhvit project, CO₂ is primarily obtained from an LNG processing plant by the scrubbing method (Chiaramonte et al. 2015), transported through pipelines and injected into the 2600 m deep sandstone reservoir with a thickness of 45–75 m (MIT. Carbon Capture and Sequestration Technologies 2015). The storage capacity of this reservoir was initially determined between 31 and 40 Mt, although later, it was determined that the capacity was over estimated and drilling of new

wells and fracturing operations are under consideration to increase the existing capacity (MIT. Carbon Capture and Sequestration Technologies 2015). Approximately 0.7 Mt of CO₂ was stored per annum.

Alberta Carbon Trunk Line Project

The Alberta Carbon Line Project by Enhance Energy Inc. is presently one of the giant CCS projects, with a pipeline network of approximately 149 miles, and has the capacity to store up to 14.6 Mt of CO₂ per annum. CO₂ is mainly obtained from the North West Sturgeon Refinery and Agrium Fertilizer plant (Cole and Itani 2013). The total storage capacity was initially estimated as 2 Gt, and the injection started in 2018 (GCCSI 2017).

Otway Basin Project

The Otway Basin Project, a pilot project situated in Australia and initiated in 2008, is considered the largest onshore CSS project (Ranasinghe 2013; Sharma et al. 2011). The CO₂ is obtained from CO₂-rich natural gas (Sharma et al. 2011) and injected into a low pressured gas bearing formation at a depth of 4000 m (Hortle et al. 2011). The effects of this CO₂ injection on soil and the surrounding environment was examined by Schacht and Jenkins (Schacht and Jenkins 2014). Different tests were carried out and it was concluded that the source of the CO₂ is biogenic and sufficiently shallow that the impact on the environment is insignificant. Studies are still ongoing to determine the different geomechanical and seismic hazards associated with CO₂ injection (Stirling et al. 2011).

Boundary Dam Project

The Boundary Dam Project by SaskPower is situated in Estevan, Canada and is the first commercial scale CCS project worldwide. The project has the capacity to inject 1 Mt of CO₂ per annum. Ninety percent of the CO₂ is transported via pipeline to the Weyburn field where it is used for CO₂-EOR while the remaining gas is reserved in a sandstone formation. The deepest parts of the formation were selected for CO₂ injection as they have a greater storage capacity. Different tests were performed to examine complex storage suitability and no hazardous impact was observed (Worth et al. 2014).

Cranfield Project

The Cranfield Project is situated in Mississippi, USA, in which 1.5 Mt of CO₂ obtained from the Jackson Dome is annually injected into a 15 m thick and 3000 m deep

heterogeneous sandstone formation (MIT. Carbon Capture and Sequestration Technologies 2015). Anderson et al. (2017) carried out extensive studies to inspect for CO₂ leakage, and no traces of CO₂ leakage from the subsurface were detected.

Frio Brine Pilot Project

CO₂ was injected into the Frio sandstone reservoir in two stages; 1600 t of CO₂ was injected in the first stage in 2004, while 1600 t of CO₂ was fed in the second stage in 2006 (Hovorka 2006). Before commencement of this project, CO₂ injection was carried out in hydrocarbon bearing reservoirs only (Atkinson 2014), although the primary project motives were to inject CO₂ into brine formation without inducing any hazardous impact to the surrounding environment and analyze the behavior of stored CO₂ (CSLF 2010). Continuous leakage monitoring of the storage area was proposed at the end of the project to evaluate the possibility of large-scale applications in the future (Hovorka 2006).

Ketzin Project

The Ketzin Project is situated in Ketzin, Germany, was initiated in 2008 and completed in 2009. The aim of this project was to inject CO₂ into the subsurface which can be monitored for future policies and to reveal underground information. The Stuttgart formation which is sandstone was utilized to store CO₂ (Guen et al. 2011; Möller et al. 2014; Streibel et al. 2014).

The CO₂ was transferred via pipeline and injected into the sandstone formation aquifer. In this project, 67,271 t of CO₂ was successfully deposited in the subsurface.

Citronelle Project

The Citronelle Project started in 2011 and is situated at the Citronelle oilfield, USA. The CO₂ for this project is obtained from the plant, transported through a pipeline and injected into a 335 m thick saline aquifer (Koperna et al. 2014). Chen and Liu (2011) used seismic measurements to study the geological changes in the storage zone and examine pre- and post-injection CO₂ migration; no traces of CO₂ leakage were detected so far (Citronelle Project NETL 2017).

Northern Reef Trend Project

The CO₂ for the Northern Reef Trend Project is obtained from the plant, conveyed through a pipeline and injected into a carbonate depleted reservoir which was previously under water flooding. This project was initiated in 2013 and it aims to store 1 Mt of CO₂ within a span of 3 to 5 years.

Investigations are currently underway to analyze the behavior of the fed CO₂ and to determine the CO₂ storage capability in the reservoir (Kelley et al. 2014).

Port Arthur Project

This project is located in Port Arthur, USA and began in January 2013. The CO₂ for this project is obtained from a refinery, transported in two stages via pipelines, and used for the CO₂-EOR process. From commencement till May 2013, approximately 222,000 t of CO₂ were injected, resulting in 1.6 to 3.1 million bbl of additional oil recovery (Eng 2014).

Zama Project

The Zama Project began in 2006 with the objective of testing acid gas injection to enhance oil recovery and minimize the cost of CO₂ purification. The gas stream consists of 70% CO₂ and 30% H₂S which is obtained from a plant and fed into a 1500 m deep reservoir. The project is expected to store 1.3 Mt of CO₂ and 0.5 Mt of H₂S over a period of 18 years. As a result of injecting of 80,000 t of H₂S, 35,000 barrels of additional oil was produced (Trivedi et al. 2007). Bennion and Bachu (2008) carried out extensive studies to analyze the effects of acid gas injection on reservoir conditions and the surrounding environment and found that CO₂-H₂S was both economically and environmentally favorable to a certain limit. Moreover, further experimental and numerical studies were proposed to determine the short-term and long-term effects of acid gas injection on reservoir quality.

Ordos Project

The Ordos Project is situated in China, started at the pilot scale level in 2010 and will be implemented at the commercial scale by 2020. The source of injected CO₂ is a coal liquefaction plant which emits 3.6 Mt of CO₂ annually. The CO₂ is transported through a pipeline and injected into a saline aquifer; since commencement till 2014, approximately 150,000 t of CO₂ had been injected (Luo et al. 2014). A monitoring system was used (Zhao et al. 2017) to trace CO₂ migration and it was observed that the fed CO₂ was contained inside the 450 m injection well. Moreover, no leakage of CO₂ was detected.

Conclusion and recommendations

In this study, we discussed the various efforts by different researchers to study CO₂ storage in different underground storage types. Specifically, the various research efforts based

on experimental, modeling and field studies were reviewed. In the study, we determined that effects such as lithology, capillarity, and chemical reactions significantly influence the behavior of CO₂ during the sequestration process. Additionally, it was identified that the depleted (or saline) reservoir offers the best storage medium for CO₂. After the injection of CO₂ within the subsurface, understanding the interaction between the different fluids and the rocks and the geologic and geochemical characteristic of reservoir rock types are needed for a successful modeling study. In this study, it was observed that there exist various successful field studies aimed at storing CO₂ underground. Examples of such projects include In Salah and Sleipner in Algeria and Norway, respectively. Though other unsuccessful field studies exist, it is worthy to mention that proper design, injection, and monitoring of these CO₂ storage projects will give additional insights into this highly effective and common method of CO₂ storage.

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Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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