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Injectivity and quantification of capillary trapping for CO_2 storage: A review of influencing parameters

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Abstract

CO_2 injection for storage in subsurface geologic medium is one of the techniques developed in the past years to mitigate anthropological CO_2. Prior to CO_2 injection, it is essential to predict the feasibility of medium in terms of storage capacity, injectivity, trapping mechanisms, and containment. There have been many studies regarding techniques which can be applied to ensure the safety of CO_2 injection. However, there are few studies indicating the importance of capillary trapping during and after CO_2 injection. The aim of this study is to review the fundamentals of injectivity and its relationship with capillary trapping for CO_2 storage in depleted oil and gas reservoirs. Considering the number of effective parameters which are associated with the injectivity and capillary trapping, it is recommended to perform a comprehensive analysis to determine the optimum injection rate and safe storage medium before operation.

Keywords

CO_2 storage, injectivity, effective parameters, capillary trapping, containment

1. Introduction

There have been many reports published in the past decades indicating a significant increase in the amount of greenhouse gas and CO_2 in the atmosphere (Akintunde et al., 2013; Bachu, 2003; Metz et al., 2005; Polak et al., 2015). Storage is a key technology to mitigate this negative impact of CO_2 on the environment by injecting it into subsurface geological mediums such as depleted oil and gas reservoirs, deep coal beds, and deep saline

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aquifers (Ketzer et al., 2012; Okabe et al., 2008; Orr, 2009; Solomon, 2007; Surdam, 2013). Table 1 compares different storage mediums based on their capacity, cost, integrity and technical feasibility. Comparatively, depleted oil and gas reservoirs are more reliable due to their more reasonable capacity and technical feasibility, as well as proven storage integrity (Herzog et al., 1997).

Table 1: Comparison of desirable geologic storage sites (Herzog et al., 1999)

Storage Option	Relative Capacity	Relative Cost	Storage Integrity	Technical Feasibility
Active Oil Well (EOR)	Small	Very Low	Good	High
Coad Beds	Unknown	Low	Unknown	Unknown
Depleted oil/gas wells	Moderate	Low	Good	High
Deep Aquifers	Large	Unknown	Unknown	Unknown
Mined caverns/ salt domes	Large	Very High	Good	High

CO_2 injectivity in the depleted reservoirs depends mainly on storage capacity and petrophysical properties of selected interval(s) (Ambrose et al., 2008). This injection may result in creation of four trapping mechanisms in storage formations including: (i) structural and stratigraphic trapping, where a CO_2 plume is stopped by an impermeable cap rock (Burnside and Naylor, 2014b; Ketzer et al., 2012), (ii) capillary trapping, where a fraction of CO_2 is immobilized and remains in the pore space as residual CO_2 gas saturation (Sgr_{CO2}) (Juanes et al., 2006; Pentland, 2011; Qi et al., 2008b), (iii) solubility trapping, where CO_2 dissolution into brine results in having a dense CO_2-saturated brine, (Al Mansoori, 2009; Iglauer, 2011; Juanes et al., 2006; Solomon, 2007), and (iv) mineral trapping due to reaction of solid mineral and CO_2 saturated brine (Jalil et al., 2012; Juanes et al., 2006; Le Gallo et al., 2002). Comparatively, capillary trapping is an efficient and rapid mechanism for CO_2 storage (Burnside and Naylor, 2014a; Cheng, 2012; Juanes et al., 2006; Lamy et al., 2010; Pentland et al., 2011a; Pentland et al., 2011b; Qi et al., 2009) because it spreads CO_2 over a larger reservoir volume, and provides more rock volume for mineral weathering and dissolution trapping (Wildenschild et al., 2011).

There have been several studies on the parameters which may have a significant impact on CO_2 injectivity (Alkan et al., 2010; André et al., 2014; Giorgis et al., 2007; Oldenburg and Doughty, 2011; Yoo et al., 2013). However, there are only few studies emphasizing the

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impact of flow rate on capillary trapping (Shamshiri and Jafarpour, 2012; Soroush et al., 2013; Wildenschild et al., 2011). This paper provides a review of injectivity and selection of injection rate for a storage medium due to the effect of capillary trapping.

2. CO_2 Injectivity and geomechanical parameters

Injectivity is generally referred as a ratio between injection rate and differential pressure between bottom hole pressure (P_{bh}) and reservoir pressure (P_{res}), as given in Eq.(1) (Bacci et al., 2011).

$$I = \frac{q_{inj}}{P_{bh} - P_{res}} \quad (1)$$

Stratigraphic factors such as permeability and thickness are important parameters which influence the quality of injection job (Ambrose et al., 2008), even though high permeability may accelerate CO_2 migration and reduce the effective storage capacity of a medium (Cooper, 2009).

There is however another definition which describes injectivity as "the ease with which fluid can be injected into a storage medium without fracturing the formation". The maximum differential pressure in this sense is defined as the difference between reservoir pressure and cap rock fracture pressure which should not be excessed, as otherwise fractures will be initiated causing the CO_2 to escape from storage medium (Burke, 2011). Thus, to have an effective injection process, pore and fracture pressures of the formations are required to be known. To determine the pore pressure, direct methods including Modular Dynamic Formation Tester (MDT) (Chopra and Huffman, 2006) or indirect approaches such as empirical correlations can be used (Eaton, 1975; López et al., 2004; Zhang, 2011). Determination or estimation of fracture pressure, on the other hand, may not be a straightforward task and requires formation pore pressure, in-situ stresses, and Poisson's ratio to be known. Although Leak-Off Test (LOT) data are available for casing shoes intervals, continuous estimation of fracture pressure for the entire cap rock and reservoir intervals may be required for accurate estimation of injection rate. LOT in this case can be used only for calibration of predictions made by empirical correlations, where attempts are made to predict the magnitude of minimum horizontal stress. This is due mainly to the fact that according to studies performed on rock fracture pressure estimation, minimum horizontal

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stress will be equal to the amount of pressure which needs to be exceeded to propagate fracture in any formation (Aadnoy and Looyeh, 2011). Determination of this horizontal stress is not straightforward and there have been many studies proposing different approaches to estimate the values of horizontal stresses (Maleki et al., 2014; Aadnoy and Looyeh, 2011). Aadnoy and Looyeh, (2011) presented a summary of techniques conventionally used for pore pressure and in-situ stress measurement/estimation which is listed in Table 2.

Table 2: Different methods used for in-situ stresses and pore pressure determination (Aadnoy and Looyeh, 2011)

Measurement Parameter	Types Of Stress	Measurement Approach	Estimation Approach
Reservoir Pressure	P_{res}	▪ Drillstem Test (DST) ▪ Repeat Formation ▪ Modular Formation Dynamics Test ▪ Logging While Drilling (LWD) ▪ Measured Direct Tests (MDT)	▪ Density Log ▪ Sonic Log ▪ Seismic Velocity ▪ Mud Weight Used
Stress Magnitude	σ_v	▪ Density Log	
	σ_H		▪ Breakout ▪ Mud Weight ▪ Observations of Well Failure
	σ_h	▪ Hydraulic Fracturing	▪ Leak-off (LOT) Test ▪ Formation Integrity Test ▪ Lost Circulation ▪ Drilling Induced Fracs
Stress Orientation	$\sigma_h or\ \sigma_H$	▪ Cross Dipole ▪ Mini-frac ▪ Hydraulic Fracture Test ▪ Drilling Induced Fracs ▪ Breakout	▪ Fault Direction ▪ Natural Frac Direction

It should be noticed that, depletion and injection changes the state of in-situ stresses in the reservoir. Streit and Hills (2002) pointed out that reservoir depletion affects the state of stress and increase the chance of rock fracturing. They concluded that effective horizontal in-situ stress increases by 50–80% as pore pressure decreases during the depletion (Streit and Hillis, 2002). Thus, considering the injection effect on storage medium, variation of pore pressure will have direct effect on poroelastic behavior of rocks (Hangx et al., 2013), and if reservoir pressure becomes sufficiently high, deformation of reservoir or seal rocks may result in creation of fractures, or reactivation of larger faults within the reservoir (Metz et al., 2005; Rutqvist, 2012). Thus, there is an inevitable link between geomechanics and CO_2 storage which should not be neglected in order to have a safe injection and storage in desired geologic mediums.

2.1. CO_2 Injectivity and effective parameters

There have been many studies on the effective parameters which may have an impact on the injectivity of CO_2. For example, Saeedi and Rezaee, (2012) did a core flooding study to evaluate the ability of rocks in flowing CO_2. Andrew et al., (2014) performed a flow dynamics modeling by computed tomography scanning during CO_2 flooding. Variation of rock strength after CO_2 flooding was tested by Hangx et al., (2013) and Tran et al., (2010) through a series of geomechanical testing. Hangx et al., (2013) used ultrasonic tests to monitor the movement of CO_2 in a reservoir. Burton et al., (2009) reported an injectivity evaluation on CO_2/brine relative permeability curves. They used Darcy's Law and a modified Buckley-Leverett fractional flow to account for partial solubility of CO_2 and H_2O at a constant pressure. They also observed a four-fold variation in injectivity and speeds of saturation at different CO_2/brine relative permeability curves. Oldenburg and Doughty (2011) did a numerical investigation on the impact of residual gas (S_{gr}) on injectivity in an idealized one-dimensional system. They indicated that injectivity declines by decreasing the liquid-phase relative permeability in the presence of residual gas. It was also found that mixing of residual gas with supercritical CO_2 reduces viscosity and density of gas mixture, which affects the injectivity. Saeedi and Rezaee (2012) experimentally studied the capillary trapping of sandstone core samples after saturation by CO_2 and brine. They concluded that presence of residual natural gas saturation may have a significant impact on CO_2 injectivity in a short-term.

On the other hand, recent numerical simulations have indicated that injection of supercritical CO_2 may have a remarkable effect on the zones located close to the injection wells. In fact, as injection progresses, CO_2 dissolution, pH variation of original brine and mineral dissolution/precipitation take place in the zones around the injection well (Alkan et al., 2010; André et al., 2014; Ennis-King and Paterson, 2007; Huq et al., 2012). These reactions change the rock properties around the well and cause the injectivity to decrease

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(Bacci et al., 2011; Metz et al., 2005). Bacci et al., (2011) summarized these reactions as below:

$$CO_2 + H_2O \rightleftharpoons H_2CO_3 \rightleftharpoons H^+ + HCO_3^- \quad (2)$$

$$H^+ + HCO_3^- + CaCO_3 \rightleftharpoons Ca^{2+} + 2HCO_3^- \quad (3)$$

$$H^+ + HCO_3^- + MgCO_3 \rightleftharpoons Mg^{2+} + 2HCO_3^- \quad (4)$$

$$H^+ + HCO_3^- + FeCO_3 \rightleftharpoons Fe^{2+} + 2HCO_3^- \quad (5)$$

The above reactions may occur in a relatively shorter period of time in carbonates compared to silicate minerals which might be related to variation of pressure and temperature. At reservoir scale, the solubility of carbonates declines as pressure drops with advancement of injection fluids (Bacci et al., 2011). Hangx et al. (2013) studied the effect of CO_2 dissolution on mechanical properties of sandstone and carbonate samples by performing triaxial, ultrasonic and CT scan tests. They found that there is no significant effect on mechanical properties of samples due to existence of quartz-cemented grain-to-grain fillers. Zheng et al. (2015) studied the effect of CO_2-NaCl solution on mechanical, hydraulic, and chemical properties of sandstone rocks. They showed that as dissolution increases, mechanical properties of rocks undergo significant changes due to variation of pH and permeability.

Precipitation is another mechanism which may cause changes in injectivity of CO_2, as mentioned earlier. There have been lots of studies on the impact of precipitation, where changes in permeability for a single phase system was considered (Civan, 2001; Pape et al., 1999; Zhu et al., 2007). In fact, variations of injectivity due to salt precipitation have been reported to be due mainly to the changes in permeability and capillary forces of selected formations (Alkan et al., 2010; Giorgis et al., 2007). Recent experimental works have shown that rock permeability reduction causes a significant drop in injectivity (André et al., 2014; Ott et al., 2015; Peysson et al., 2014), although carbonate mineralization (Yoo et al., 2013) and mineral dissolution may also contribute into this decline (André et al., 2014).

Injection of CO_2 with different impurities (e.g., SOx, NOx, H_2S) may also change the quantity of storage in a geologic medium (Metz et al., 2005). Knauss et al. (2005) and Wang et al. (2011) pointed out that chemical, mobilization and mineral reactions caused by impurity are quite different from those caused by pure CO_2 (Knauss et al., 2005; Wang et al., 2011). According to Wang et al., (2011), who did a study on the effect of H_2S and SO_2 on CO_2 injectivity, H_2S has no significance impact on the injection while the effect of SO_2 cannot be

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ignored. Table 3 gives a summary of some of the recent studies performed on the effect of dissolution, precipitation and impurities on CO_2 injectivity.

Table 3: Summary of earlier works performed on the effect of dissolution, precipitation and impurities on CO_2 injectivity

Reference	Approach	Medium	Remarks
(Burton et al., 2009)	Simulation	Aquifer	Change in injectivity with the injected volume
(Hangx et al., 2013)	Experimental		No prominent effect on the rock strength due to CO_2 injection
(Oldenburg and Doughty, 2011)	Simulation	Aquifer	Residual natural gas in depleted reservoir lowers the CO_2 injectivity
(Saeedi and Rezaee, 2012)	Experimental	Depleted gas	Residual natural gas in depleted reservoir lowers the CO_2 injectivity during the early stages of CO_2 injection
(Giorgis et al., 2007)	Simulation	Depleted gas	Sufficient brine mobility due to capillary pressure gradient result concentrated halite precipitation which affect the injectivity
(Bacci et al., 2011)	Experimental & Simulation	Aquifer	Change in Injectivity at various distances from the wellbore at various pressures and temperature shows that dissolution/precipitation have the significant effect on injectivity.
(Wang et al., 2011)	Theoretically with experimental data	Aquifer	Change of density due to non-condensable gas impurity such as SO_2 lower the injectivity
(Yoo et al., 2013)	Experimental	-	Pore throat clogging mechanism of carbonate mineral precipitate while groundwater enriched in $CaCO_3$ used.
(Liu et al., 2013)	Experimental	Aquifer	Salt precipitation occurs only in pore space occupied by brine during the precipitation process result permeability change
(Peysson et al., 2014)	Experimental	Aquifer	Injection of dry gas results drying and salt precipitation which lower the rock permeability by clogging pores or by pore throat restriction
(Dawson et al., 2014)	Experimental	Aquifer	Pure CO_2 or mixed SO_2–CO_2 gas results dissolution of carbonate minerals occurs in sandstone while K-feldspar don't show any change for 360 h at 50 °C and 10MPa.
(André et al., 2014)	Experimental & Simulation	Aquifer	Mineral dissolution/precipitation result change in permeability and injectivity caused by the interplay of capillary forces and the salinity of the initial brine
(Zheng et al., 2015)	Experimental	Aquifer	Deformation of porous quartz–feldspar–detrital sandstone occurs by dissolution effect due to a water chemical environment (NaCl solution and CO_2–NaCl solution) in both short and long-terms.
(Ott et al., 2015)	Experimental	Aquifer	Drying and salt precipitation affect during dry CO_2 injection which ultimately affect the permeability in unimodal sandstone

There have also been many numerical studies discussing on the injectivity of a CO_2 storage medium (Cinar et al., 2008; Di Pasquo et al., 2014; Jalil et al., 2012; Qi et al., 2008a). For example, Cinar et al. (2008) carried out a numerical study on feasibility of CO_2 injectivity in low and high permeable formations. Solubility of CO_2 in brine and chemical reactions of CO_2 with rock matrix during injection were not considered in their simulation. They concluded that injectivity cost is sensitive to permeability and high permeability zones are better options compared to low permeable zones for storage purposes. Qi et al., (2008a) studied on simultaneous injection of CO_2 and brine. They provided a very good discussion on field-scale oil production and CO_2 storage using a streamline based simulator which could capture dissolution, dispersion, gravity and rate limited reactions in three dimensions. Oruganti and

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Bryant, (2009) carried out a simulation analysis to evalute the effect of faults geometry and rock compressibility in aquifers. They showed that pressure build-up and injectivity is affected by the variation of fluid viscosity, pressure and temperature. Jalil et al. (2012) analytically calculated the storage capacity of a medium with evaluation of injection rates, and trapping mechanisms, where hysteresis effect was considered. They also covered geomechanical aspects associated with CO_2 injection to verify the field potential in terms of cap rock integrity. Zhang et al. (2013) studied on the injectivity potential of an aquifer at a constant injection pressure. They reported an improvement in injectivity through individual factors such as having horizontal wells, thicker medium and hydraulic fractures. They also noticed the minor effect of change in fluid temperature on injectivity. Di Pasquo et al. (2014) dealt with overpressure concern by optimization of injection strategy. They indicated a significant change in injectivity due to phase changes caused by interactions between fluids and rocks. Table 4 gives a summary of recent works which used numerical simulation to assess the feasibility of storage medium for CO_2 injection.

None of the studies used simulation to evaluate the injectivity, except the one carried out by Jalil et al. (2012), highlighted the importance of evaluating the fracture gradient/pressure of the reservoir or cap rock intervals. This is while the effect of these parameters as discussed above is important.

Table: 4: Summary of earlier simulation studies of CO_2 injectivity

Reference	Fracture Pressure/Fracture Gradient	Storage Medium	Injection Rate	Remarks
(Cinar et al., 2008)	Not Mentioned	Aquifer	70 Mt/y	injectivity cost is sensitive to permeability
(Qi et al., 2008b)	Not Mentioned	Oil	7.1×10^5 kg/day	analytical solution to design injection strategy for chase water injection
(Oruganti and Bryant, 2009)	Not Mentioned	Aquifer	74 MMscfd	injectivity is affected by the variation of fluid viscosity
(Oldenburg and Doughty, 2011)	Not Mentioned	Aquifer	100 t CO_2/day	injectivity is affected by the variation of fluid viscosity, density and presence of residual gas
(Jalil et al., 2012)	4200psi	Depleted condensate carbonate gas field	200 to 1000 MMScf/day	well injectivity issues at different well/field injection rates in different zones
(Zhang et al., 2013)	Not Mentioned	Aquifer	Different rates	fluid temperature don't have a significant effect on the injectivity
(Di Pasquo et al., 2014)	Not Mentioned	Aquifer	1 Mt CO_2/y and 10 Mt CO_2/y injection rates	different simulation codes were showing good agreement
(Ganesh et al., 2014)	Not Mentioned	Oil field	-	phase changes and fluid interactions affect the injectivity

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2.4 Capillary Trapping and Injection Rate

Generally speaking, physical process in which CO_2 is immobilized as a residual gas saturation (Sgr_{CO2}) in pore spaces due to capillary force is called capillary trapping (Burnside and Naylor, 2014b; Cheng, 2012; Juanes et al., 2006; Pentland, 2011). This mechanism takes place when CO_2 is injected into a targeted geological medium, forming a continuous plume. CO_2 plume in these situations is flowing upwards by buoyancy and chased by water at the trailing edge of the rising plume in a re-imbibition process (Pentland et al., 2011a).

A number of parameters have been highlighted with impacts on capillary trapping of residual CO_2 including pore aspect ratio (Pentland, 2011; Tanino and Blunt, 2012), initial gas-phase saturation (Al-Menhali et al., 2014; Pentland et al., 2011b; Suekane and Nguyen, 2013), initial oil saturation (Al Mansoori et al., 2010; Pentland et al., 2008), interfacial tension (Bennion and Bachu, 2006) and CO_2 viscosity (Harper, 2013). Pore geometry (Holtz, 2003; Iglauer et al., 2009; Pentland et al., 2012; Suekane et al., 2010; Tanino and Blunt, 2012), wettability (Chalbaud et al., 2007; Chalbaud et al., 2009; Farokhpoor et al., 2013; Iglauer et al., 2015; Soroush et al., 2013), rock type (Andrew et al., 2014), presence of impurities in CO_2 gas stream (Metz et al., 2005; Wang et al., 2011) and hysteresis (Jalil et al., 2012; Juanes et al., 2006) may also contribute into changes in capillary trapping.

On the other hand, porosity (Iglauer et al., 2009; Lamy et al., 2010; Pentland, 2011; Suekane et al., 2010; Tanino and Blunt, 2012), coordination number (Tanino and Blunt, 2012), capillary number (Cense and Berg, 2009), gravity number (Taku Ide et al., 2007; Bandara et al., 2011), flow rate (Akbarabadi and Piri, 2013; Shamshiri and Jafarpour, 2012; Soroush et al., 2013; Wildenschild et al., 2011) and pore pressure (Saeedi et al., 2012) may have an opposite effect on residual CO_2 saturation. For instance, Jerauld (1997) reported that porosity have an inverse effect on natural residual saturation increases. Pentland et al. (2012) indicated that there are different trends between porosity and residual CO_2 saturation in unconsolidated formations. However, they found that residual CO_2 saturation increases as porosity decreases in consolidated formation. Table 5 reviews some of the recent studies indicating the range of porosity used to study on residual CO_2 saturation.

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Table 5: Summary of recent studies used different ranges of porosity for residual CO_2 saturation modeling

Reference	Rock Type	Porosity Range
(Jerauld, 1997)	Sandstone	0-0.35
(Iglauer et al., 2009)	Unconsolidated Sandpacks Consolidated Sandstones	0.11-0.225
(Lamy et al., 2010)	Four consolidated carbonates One unconsolidated carbonate	16.32 to 43.66
(Pentland et al., 2012)	Glass bead pack, sand pack and sandstone	0.19-0.59
(Tanino and Blunt, 2012)	Limestone an Sandstone	0.13-0.28

Pore coordination number (z) which describes the topology of a pore network in a porous medium, is another important parameter having an inverse effect on residual CO_2 saturation (Tanino and Blunt, 2012). This number is formulated as below:

$$z_v = \sum_{z=1}^{z=c} z p_z(z) \tag{6}$$

where

$$pz^{(z)} = \frac{\sum_j \varepsilon_s(z) V_j}{\sum_{z=1}^{z=c} \sum_j \varepsilon_s(z) V_j}, \tag{7}$$

s(z) represents the pore bodies with coordination number, and Vj is j^{th} pore body's volume. Capillary number, which is defined as the ratio between Darcy velocity, viscosity, and interfacial tension, is another parameter with inverse relationship with residual CO_2 saturation. This number is defined as: (Cense and Berg, 2009).

$$N_c = \frac{V\mu}{\sigma Cos\theta} \tag{8}$$

where σ is interfacial tension, θ is contact angle and v stands for CO_2 superficial velocity. Cense and Berg, (2009) indicated that at approximately 10^{-5} and 10^{-3} critical capillary numbers, the residual saturation declines for non-wetting and wetting phases, respectively. Suekane et al., (2010) pointed out through direct observation of trapped gas bubbles in Berea sandstone that capillary number governs the stability of trapped gas bubbles. In the most recent study performed through X-ray micro-computer-tomography experiments, it was found that there is a systematic dependency between trapping efficiency and capillary number at 2×10^{-7} to 10^{-6} (Geistlinger and Mohammadian, 2015), which contradicts the earlier finding highlighted the inverse relationship between capillary number and residual CO_2 saturation (Al-Menhali et al., 2014).

It is very well known that there is a relationship between gravity and capillary trapping during CO_2 injection and storage. In fact, CO_2 injection displaces the natural medium's fluid, and flows vertically to spread along the caprock as a gravity current in the absence of prominent barriers. This vertical flow (gravity current) can however be immobilized due to capillary trapping. Subsequently, CO_2 during vertical flow also dissolves into the brine at the CO_2/brine interface (Riaz and Cinar, 2014). Zhou et al., (1994) defined the ratio of gravity to viscous forces with a number (N_{gv}) which describes a two-phase flow in a heterogeneous medium. This number is formulated as below.

$$N_{gv} = \frac{k_v L \Delta\rho g}{H u \mu_{brine}} \tag{9}$$

The above equation describes the relationship of vertical permeability (K_v), the reservoir length (L), the density difference $\Delta\rho$, the acceleration of gravity (g), the reservoir height (H), the total average Darcy flow velocity (u), and viscosity of brine (μ_{brine}) with gravity to viscous ratio. Iffly et al. (1997) presented a capillary-to-gravity ratio (N_{gr}) to evaluate the relative effect of gravity in the presence of capillary pressure. This ratio is formulated as below:

$$N_{gr} = \frac{2\sigma}{\Delta\rho g h \sqrt{\frac{k}{\phi}}} \tag{10}$$

where, σ is the interfacial tension, $\Delta\rho$ is the density difference, g is the gravity force, h is the medium height, k is permeability and ϕ is porosity (Soroush et al., 2013).

Many studies have discussed the important role of gravity force during CO_2 storage. For example, Taku Ide et al. (2007) studied the importance of viscous and gravity forces interactions and their effect on capillary trapping in the aquifer. They concluded that the immobile CO_2 due to capillary trapping is a function of gravity number. In fact, more CO_2 is trapped when viscous force is higher than the gravitational force (i.e., low gravity number)

(Taku Ide et al., 2007). Bandara et al. (2011) utilized pore-scale models to study the impact of gravity forces on capillary trapping during CO_2 storage. The results obtained indicated that more CO_2 will be injected to the caprock when gravity number of storage medium is high and trapping is low (Bandara et al., 2011). Polak et al., (2011) evaluated the effect of gravitational, viscous and capillary forces on the vertical flow of CO_2 in the homogeneous porous medium. They found that low injection and high permeability favor the gravity effects by forcing the fluid to flow in the vertical direction and ultimately results in less brine volume displacement. On the contrary, high injection rate reduces the gravity effect due to strong viscous forces, resulting in more brine volume displacement.

There have also been many studies discussing the effect of injection rate on capillary trapping. For example, Mansoori (2009) evaluated the impact of flow rate on capillary trapping within capillary-controlled limit. He indicated that there will not be any changes in amount of gas entrapment as long as capillary number is less than 10^{-5}. In fact, recent research studies revealed that high injection rates suppress the snap-off process and result in low residual CO_2 saturation (Wildenschild et al., 2011). Soroush et al., (2013) carried out experimental studies to evaluate the effect of injection rate on residual CO_2 saturation in drainage and imbibition processes. They observed that residual CO_2 saturation is sensitive to imbibition rate if porous medium has less wettability in its wetting phase. Nguyen et al., (2006) reported that slow displacements rates, high pore-throat aspect ratios, and zero contact angle favor snap-off process. According to Shamshiri and Jafarpour (2012), injection rate can be monitored to optimize the capillary trapping. Akbarabadi and Piri (2013) performed unsteady state core flooding experiments to investigate the capillary trapping and dynamic effects of high brine flow rate during imbibition using CO_2 + SO_2/brine. They noticed the negative impact of high brine injection rates in imbibition on capillary trapping. Saeedi et al. (2012) experimentally showed that the increase in effective pressure due to an increase in overburden stress at constant injection rate results in more capillary trapping in the samples. On the contrary, increase in pore pressure causes reduction in residual CO_2 saturation due to variation in fluid properties. It can then be concluded that since injection rate may cause changes in in-situ stress magnitudes in the storage medium, it is expected to see different capillary trapping phenomenon at different stages of injection. It is also clear that measurements of in-situ stress and pore pressure are required for having safe injection pressures (Fjar et al., 2008a). However, high permeability channels improve CO_2 migration and gravity current reduces the effective storage capacity within the targeted storage medium which in turn increases the risk of leakage at field scale level. Table 6 summarizes some of the recent studies discussing on capillary trapping ability of geologic mediums. Based on the results presented in this Table, it is recommended to carry out X-ray CT core scanning system for fracture analysis before and after capillary trapping experiments to ensure the sustainability of core sample against the pressure of injection.

Table 6: Summary of reviewed papers on capillary trapping measurements

Reference	Fluids System	Experimental Conditions	Rock	Flow Rate	Capillary Number	Major Measurements	Approach
(Bennion and Bachu, 2006)	CO_2 –brine	43 °C; 1.37-20 MPa	Sandstone	10 cm^3/hr	-	Capillary Trapping	Experimental
(Mansoori et al., 2009)	Oil-water Gas-water	20 °C; 0.101 MPa	Unconsolidated Sandpacks	5ml/min	1 x 10^{-5} to2 x 10^{-6}	Capillary Trapping	Experimental
(Lamy et al., 2010)	Oil (n-octane)-water	Ambient temperature and slightly elevated pressure	consolidated & unconsolidated carbonates	-	<8 x 10^{-7}	Capillary Trapping	Experimental
(Pentland et al., 2010)	Octane-brine	20 °C; 0.101 MPa	Sandpacks	2 mL/min 20 mL/min 20 mL/min	2.66 x 10^{-7} 2.66 x 10^{-6} 5.66 x 10^{-6}	Capillary Trapping	Experimental
(Wildenschild et al., 2011)	Air, octane and Soltrol 220 (NWP) Brine (WP) Triton 1, Triton 2, Triton 3, Triton 4, Triton 5 and Triton 6, Glycerol 1, Glycerol 2. (WP) Air (NWP)	21- 22 °C; 0.101 MPa	Sintered glass bead pack.	2 to 10 mL/hr	10^{-8} to 10^{-6}	Capillary Trapping	Experimental
(Pentland et al., 2011b)	CO_2-water Oil (n-decane)-water	70 °C; 9 MPa	Sandstone	-	4.1 x 10^{-7}	Capillary Trapping	Experimental
Krevor et al. 2012	CO_2-water	50 °C; 9 MPa	Sandstone	15 mL /min	10^{-8} to 10^{-7}	Capillary Trapping	Experimental
(Tanino and Blunt, 2012)	n-Decane-water n-Octane-water	20 °C; 0.101 MPa	Sandstone and Limestone	maximum	1.1 x 10^{-6}	Capillary Trapping	Experimental
(Saeedi and Rezaee, 2012)	CH_4-CO_2-water	83 °C; 17.78 MPa	Sandstone	Now wetting: 300 cc/hr Wetting phase: 200 cc/hr	2.65 x 10^{-6} to 9.65 x 10^{-5}	Injectivity and capillary trapping	Experimental
(Suekane and Nguyen, 2013)	N_2-water	45 °C; 8 MPa	Sandstone	1.0 ml/min	4.8 × 10^{-6} .	Capillary Trapping	Experimental
(Harper, 2013)	Air, octane and Soltrol 220 (NWP)- Brine (WP) Triton 1, Triton 2, Glycerol 1 and Glycerol 2 (WP) – Air (NWP)	22 °C; 0.101 MPa	two sintered, soda lime glass bead columns	0.25 mL/hr (primary imbibition) 2-500 mL/hr (secondary imbibition)	10^{-3} to 10^{-6} (based on secondary imbibition)	Capillary Trapping	Experimental
(Akbarabadi and Piri, 2013)	CO_2+SO_2 - brine	60 °C; 19.16 MPa	Limestone	**brine flow rate** (cm^3/min) Drainage: 0.03–0.2 Imbibition: 0.03–0.16 **scCO_2-rich phase flow rate** (cm^3/min) Drainage: 0–0.1 Imbibition 0–0.08	≤ 10^{-5}	Capillary Trapping	Experimental

Summary

Injectivity and capillary trapping are the two important aspects which govern the long-term safety of CO_2 storage projects. Injectivity, which is primarily linked to permeability and thickness, would be required to be determined accurately for avoiding fracture initiation in the storage medium. Pore pressure and in-situ stress magnitudes are the two necessary parameters which need to be calculated for having a safe injection without fracturing the reservoir and caprock.

There are many important parameters with positive or negative impact on permeability and injectivity which should not be neglected to have a safe injection and storage of CO_2 in depleted reservoirs. Last but not least is the effect of injection on changes in the magnitude of in-situ stresses which may change the initial estimation made for fracture pressure of reservoir and caprock. It is also known that injection flow is very relevant to capillary trapping. Therefore, it is suggested to do fracture analysis before and after capillary trapping experiments to evaluate rock sustainability at selected injection rate.

Nomenclature

CO_2	carbon dioxide	N_2	nitrogen
q_{inj}	injection rate	P_{res}	reservoir pressure
P_{bh}	bottom hole pressure	R_a	Pore aspect ratio
S_{gr}	natural residual saturation	S_{gi}	initial gas saturation
S_{oi}	initial oil saturation	S_{grCO2}	residual CO_2 saturation
S_w	wetting phase saturation	S_{nw}	non-wetting phase saturation
σ	interfacial tension	φ	porosity
z	coordinate number	N_c	capillary number
N_{gv}	gravity number	N_{gr}	capillary to gravity raito
k_v	vertical permeability	L	length of storage medium
$\Delta\rho$	density difference	μ	dynamic viscosity
μ_{brine}	viscosity of brine	u	total average Darcy flow velocity
H	height of storage medium	g	gravity force
r	pore throat size	θ	contact angle
V	CO_2 superficial velocity	K	permeability
V_j	volume of the jth pore body	^oC	centigrade
MPa	mega Pascal	s(z)	set of pore bodies with coordination number (z)

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