Egyptian Journal of Petroleum (2016) **25**, 367–373

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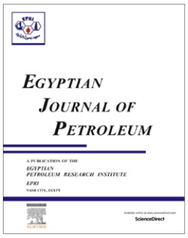

REVIEW

Carbon dioxide storage in subsurface geologic medium: A review on capillary trapping mechanism

Arshad Raza [a,*], **Reza Rezaee** [b], **Chua Han Bing** [c], **Raoof Gholami** [a], **Mohamed Ali Hamid** [a], **Ramasamy Nagarajan** [d]

[a] *Department of Petroleum Engineering, Curtin University, Sarawak Malaysia, CDT 250, 98009 Miri, Sarawak, Malaysia*
[b] *Department of Petroleum Engineering, Curtin University, Kensington 6151, Western Australia, Australia*
[c] *Department of Chemical Engineering, Curtin University, Sarawak Malaysia, CDT 250, 98009 Miri, Sarawak, Malaysia*
[d] *Department of Applied Geology, Curtin University, Sarawak Malaysia, CDT 250, 98009 Miri, Sarawak, Malaysia*

Received 27 June 2015; accepted 24 August 2015
Available online 30 November 2015

KEYWORDS

CO_2 storage;
Capillary trapping;
Depleted hydrocarbon reservoir;
Effective parameters

Abstract Carbon dioxide (CO_2) storage in subsurface geologic medium is presently the most promising option for mitigating the anthropogenic CO_2 emissions. To have an effective storage in immobile phase, however, it is necessary to determine the distribution of CO_2 in a medium, which mainly depends on three trapping mechanisms known as capillary, dissolution and mineral mechanisms. Previous studies have emphasized on these mechanisms individually in different aspects, particularly by considering the aquifer system. The purpose of this review is to give a comprehensive discussion on the advancement made toward capillary trapping in terms of effective and non-effective factors. It also throws light into the importance of capillary trapping in depleted hydrocarbon reservoir. Considering various factors and their impacts on capillary trapping, it is suggested to carry out an integrated study for the assessment of the major and minor influential parameters for better modeling and understanding of capillary trapping in any storage medium.

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[*] Corresponding author.

E-mail address: arshadraza212@gmail.com (A. Raza).

Peer review under responsibility of Egyptian Petroleum Research Institute.

http://dx.doi.org/10.1016/j.ejpe.2015.08.002

Abbreviations

CO_2	carbon dioxide
S_{grnw}	non-wetting residual saturation
S_{grCO_2}	residual CO_2 saturation
S_{gr}	natural residual saturation
θ	contact angle (degree)
q	flow rate
C	land trapping coefficient
MPa	mega pascal
φ	porosity
N_c	capillary number
V	CO_2 superficial velocity
μ	dynamic velocity
r	pore throat size
dynes/cm	dynes/centimeter
S_{gi}^{*}	effective initial gas saturation
mN/m	millinewton per meter
S_{gi}	initial gas saturation
$S_{gr}^{\max}$	maximum residual gas saturation
S_{oi}	initial oil saturation
K	permeability (mD)
IFT	interfacial tension (dynes/cm)
S_{gr}^{*}	effective residual gas saturation
m	meter
atm	atmospheric
°C	centigrade
cP	centipoise
R_a	aspect ratio
psi	pounds per square inch

1. Introduction

CO_2 emissions in the atmosphere as a consequence of anthropogenic activities are increasing [1–5]. CO_2, in fact, contributes up to 70% to global warming and, therefore, known as a major anthropogenic greenhouse gas [6]. CO_2 storage into subsurface geological medium is a major technology to mitigate this global issue [4,7–10]. Available storage mediums for CO_2 injection include deep saline aquifer, active and depleted oil and gas fields, unminable deep coal seams and mined salt domes. Table 1 summarizes advantages and disadvantages of different geologic mediums conventionally used for CO_2 storage [11].

Comparatively, depleted hydrocarbon reservoirs are considered as the most appealing place of permanent, safe and economical storage of CO_2 [12,13]. These reservoirs are deep enough to safely store CO_2 without contamination of subsurface resources. In addition, they had preserved oil and gas for a long time in elevated temperature and pressure, and can therefore mitigate the risk of leakage in long term storage. In addition, these depleted hydrocarbon storage mediums can provide a temperature of 175 °C and a pressure of 70 MPa which is required for CO_2 to appear under supercritical conditions [14].

Typically, injection of CO_2 in storage medium leads to four trapping mechanisms including (i) structural and stratigraphic trapping, when upward movement of CO_2 plume is stopped by an impermeable cap rock [7,15], (ii) capillary trapping, when CO_2 is rendered immobile as a residual phase in porous storage medium [16–18], (iii) solubility trapping, when CO_2 dissolved into brine and denser CO_2-saturated brine sinks slowly in the storage medium [6,17,19], (iv) mineral trapping, when dissolved CO_2 in brine reacts with storage medium [16,17,20]. Solubility trapping depends mainly on diffusion of CO_2 in a storage medium [9,17]. Owing to this, many studies have pointed out solubility [19] and mineral trappings [16,17,20] as a long-term process. However, capillary trapping is the most efficient mechanism with rapid entrap of CO_2 when it is compared to other trapping mechanisms [21–23]. However, when it comes to depleted hydrocarbon storage mediums, capillary trapping measurements/prediction is usually excluded. There are, however, few studies on residual CO_2

Table 1 Advantages and disadvantages of different CO_2 storage geologic mediums [11].

Storage medium	Advantage	Disadvantage
Unminable coal seams	• Large capacity • Enhanced methane production	• High cost • Not available in all regions
Deep saline aquifers	• Large capacity • Widespread availability	• Unproven storage integrity
Mined salt domes	• Custom design • Storage integrity	• High cost • Not available in all regions
Active or depleted oil and gas reservoirs	• Proven storage integrity • Established Infrastructure • Enhanced hydrocarbon recovery	• Not available in all regions • May not be available for immediate injection • Uncertainties associated with existence of residual hydrocarbon

saturation estimation by considering capillary trapping [16,17,24–26] where measurements procedure of this efficient trapping mechanism in the lab has been presented [8,27–29]. The aim of this paper is to provide a comprehensive review on capillary trapping mechanism and its effect on CO_2 storage medium during and after the injection. This review also hopes to be beneficial in the better understanding of capillary trapping which takes place in active oil recovery fields under CO_2 injection.

2. Capillary trapping in depleted hydrocarbon reservoirs

The key concern with CO_2 storage is to ensure that it will stay underground after CO_2 injection without any potential leakage to the atmosphere [17,27]. Owing to this, the security of CO_2 storage rely on the combination of trapping mechanisms mentioned earlier [30]. In fact, immobilization of CO_2 due to trapping in a storage medium mitigates the leakage concern and enhances the storage security level [26].

According to the recent studies, capillary trapping is a rapid and more efficient mechanism to entrap CO_2 in subsurface formations compared to other trapping mechanisms [21–23]. There are in fact many advantages in having capillary trapping in a storage medium. First, and foremost, having higher capillary force higher than buoyant force causes the CO_2 to appear as pore-scale bubbles rather than being constrained by compromised cap-rock [31]. Secondly, depleted oil and gas reservoirs are more sophisticated than aquifer in terms of storage integrity as they had stored hydrocarbons in the past [32,33]. In these reservoirs, capillary trapping would be more efficient and risk of tragic failure associated with structural trapping will not be an issue over a short period of time [16]. Thus capillary trapping would be the dominant trapping mechanism in first hundred years of storage life [3]. It should also be noticed that capillary trapping results in a large surface-to-volume ratio which enhances the solubility of CO_2 into the brine and gives access to a larger rock volume for mineral precipitation [31]. As a result, when it comes to having a good storage medium, capillary trapping is one trapping mechanism which cannot be neglected.

2.1. Capillary trapping due to snap-off process

Injection of CO_2 in storage medium forms a continuous plume, which flows upward by buoyancy. Subsequently, water chases the CO_2 at the trailing edge of rising plume in a re-imbibition process and immobilizes a portion of CO_2 by capillary forces [34]. Thus, capillary trapping in its general term is referred to a process in which CO_2 is immobilized and appear as residual gas saturation (S_{grCO_2}) in storage medium due to capillary forces. The process of immobilization of CO_2 due to capillary force is generally called snap-off [17,21,22,28]. In fact, at pore scale level, snap-off is a phenomenon when water fills narrow regions of the pore space, leaving ganglia of CO_2 surrounded by water in large pore spaces [6]. Holtz (2003) stated that storage mediums have residual CO_2 saturations in a range of 5–25%. There is however another trapping mechanism known as local capillary trapping, which occurs in heterogeneous storage mediums. This kind of trapping occurs during the buoyancy-driven migration of bulk phase CO_2 when there is a spatial variation in the range of permeability and capillary entry pressure. Local trapping mechanism usually results in having higher saturation of CO_2 in storage medium compared to other trapping mechanisms [52].

2.1.1. Effective parameters in capillary trapping

There have been many studies discussing on the parameters affecting the capillary trapping, where attempts were made to establish relationship between residual CO_2 saturation and reservoir properties. For instance, pore aspect ratio [28,36], initial gas-phase saturation [37–39], initial oil saturation [40,41], interfacial tension [42] and CO_2 viscosity [43] were introduced as the parameters with direct impact on residual CO_2 saturation. Tanino and Blunt (2012) provided a report for residual CO_2 saturation measurements on limestone and sandstones. They concluded that as pore throat aspect ratio decreases, residual CO_2 saturation decreases. Crowell (1966) was the first one who described the significant effect of initial gas saturation on natural residual saturation [44]. Earlier studies in this area of research showed that non-wetting phase saturation increases monotonically with wetting phase saturation [45,46]. It was also found that initial oil saturation and residual CO_2 saturation are directly related to each other in sand packs [40,47], and carbonates [23,41]. Suekane and Nguyen (2013) reported that initial gas saturation strongly affects the residual gas saturation. They stated that initial gas saturation depends on pore size distribution and heterogeneity of sandstone [39].

There are many correlations which can be used to relate maximum residual saturation to a given maximum initial saturation. In most of these correlations, maximum initial saturation occurs at the time of flow reversal and is linked to hysteresis effect [48]. The Land model [45], which is expressed as Eq. (1), is a widely used well known trapping model successfully used in many occasions to relate maximum residual saturation to maximum initial saturation [46]. Relative permeability models such as those proposed by Jerauld (1997), Killough (1976) and Blunt (2000), which consider hysteresis effect in their calculations, are generally developed based on the Land model [17]. There are, however, few other models developed for the same application such as the one proposed by Spiteri (2008) which appears to be a good model for the prediction of residual gas saturation in consolidated sandstone. In addition, Jerauld trapping model (1997) developed a model for the determination of natural residual gas for mixed-wet rock by modifying the Land trapping model, as given in Eq. (3) [40].

$$S_{gr}^{*} = \frac{S_{gi}^{*}}{1 + CS_{gi}^{*}} \tag{1}$$

where,

$$C = \frac{1}{S_{gr}^{\max}} - 1 \tag{2}$$

And S_{gi}^{*}, S_{gr}^{*} and $S_{gr}^{\max}$ are the effective initial gas saturation, effective residual gas saturation and maximum residual gas saturation respectively.

$$S_{gr}^{*} = \frac{S_{gi}^{*}}{1 + \left(\frac{1}{S_{gr}^{*\max}} - 1\right) S_{gi}^{*1/(1-S_{gr}^{*\max})}} \tag{3}$$

where, $S_{gr}^{*\max}$ is the maximum effective residual gas saturation.

Table 2 gives a summary of studies that reported a relationship between initial gas saturation and residual CO_2 saturation.

Interfacial tension, defined as the imbalance of molecular forces between two phases, is another effective parameter with a direct impact on residual gas saturation [42]. Generally speaking, as interfacial tension increases in consolidated sandstone, the residual CO_2 saturation increases [42,49,50]. However, CO_2–brine interfacial tension is less than that of a hydrocarbon–brine and thus, a lower residual gas saturation is achieved in a CO_2–brine system due to a dominant snap-off trapping mechanism [51]. Wildenschild et al. (2011) did an experimental work to evaluate the effect of interfacial tension, viscosity and fluid flow rate on residual CO_2 saturation. They showed that high initial gas saturation is obtained when interfacial tension is very high, while a decrease in interfacial tension increases the non-wetting phase saturation [31]. Bennion and Bachu (2006) experimentally studied the effect of interfacial tension and brine–CO_2 viscosity ratio on residual CO_2 saturation. They reported an increase in residual CO_2 saturation as interfacial tension and brine–CO_2 viscosity ratio increases. Harper (2013) studied the impact of flow rate, wetting and non-wetting fluid viscosity and interfacial tension on capillary trapping by using proxy fluid pair experiments on unconsolidated glass bead pack. They indicated that non-wetting phase saturation increases with the increase in non-wetting phase viscosity, and suggested to control the viscosity of CO_2 for the optimization of sequestration project. Table 3 provides a summary of recent studies that reported a relationship between interfacial tension and residual CO_2 saturation.

There have been a number of studies discussing the effects of heterogeneity, pore geometry, wettability, and rock type and hysteresis on capillary trapping. According to these studies, heterogeneity may have a minor effects on local capillary trapping [35,39] while pore geometry [29,36,52–54], wettability [55–58], rock type [32] and hysteresis [16,17] may cause major changes in capillary trapping. For example, Suekane and Nguyen (2013) pointed out that residual gas saturation in local trapping will be fluctuated due to heterogeneity. This is while heterogeneity may favor local capillary trapping length by providing wider distribution of entry capillary pressure, horizontal permeability, and minor vertical length [39].

Iglauer et al. [53] did a study on pore geometry by experimental investigation and indicated that consolidated medium offers maximum capillary trapping capacity to immobile CO_2. This was almost the same observation made by Pentland et al. [54] who highlighted that narrow pore throats offer more CO_2 trapping than wider ones.

On the other hand, studies carried out to evaluate the rock type for capillary trapping demonstrated that quartz-rich sandstones [27] and carbonates [23] offer a significant capillary trapping during CO_2 displacement. According to these studies, carbonates may show completely different stress response due to fluid pressure on their pore structure [23]. Andrew et al. (2014) compared the capillary trapping capacity of sandstone with that of carbonates via pore scale imaging and indicated that sandstones offer a higher residual saturation and capillary trapping capacities compared to carbonates [32].

Wettability governs the distribution of fluid in a reservoir during CO_2 flooding. However, the interaction of CO_2–brine system with storage medium may cause changes in wettability of storage medium. Generally, this change in wettability alters capillary pressure and relative permeability [55]. Earlier studies investigated the impact of wettability on residual CO_2 saturation. They all reached the same conclusion that a strong water wet sandstone system offers significant trapping in large pores since CO_2 appears occasionally in non-wetting phase [27,38,59]. In fact, if a rock is strongly water wet, it maintains its wettability at high pressure and there will not be any changes in contact angle as a function of pressure [57,60]. It should be noticed though as pressure increases, mica would be the only mineral which may show reduction in water wettability [57]. However studies carried out by Chiquet et al. [61], Shah et al. [62] and Jung and Wan [63] pointed out that contact angle increases due to variation in pressure. Pentland et al. (2011) highlighted that residual CO_2 saturation would be very much restricted if CO_2 appears in wetting phase [34]. Chalbaud et al. (2007) indicated that CO_2 can appear in wetting phase under reservoir condition if grain surface is not completely water wet or oil-wet [55]. Apart from pressure and wettability, different phases of CO_2 may have a huge impact on contact angles when CO_2 appears in an oil-wet system. Relatively, in a water-wet pore space, the contact angles between CO_2 and fluid will not get significantly changed with the CO_2 phase [64]. Table 4 gives a summary of earlier studies carried out on contact angles under different conditions and systems.

Hysteresis is another parameter which may have a remarkable effect on capillary trapping, which can be observed due to flow reversal during an imbibition process [16,17].

There have also been many studies on porosity [23,28,29,65], coordination number [36], capillary number [66], flow rate [26,31,58], pore pressure [67], and presence of impurities in the CO_2 gas stream [3,68], where negative impacts on capillary trapping were experienced. For example, Jerauld [69] experimentally showed that naturally trapped gas

Table 2 Summary of reviewed papers on initial gas/oil saturation relationship with residual CO_2 saturation.

References	Fluids system	Experimental conditions	Rock type	Wettability
Mansoori et al. [47]	Oil–water Gas–water	20 °C; 0.101 MPa	Unconsolidated sand packs	–
Lamy et al. [23]	Oil (n-octane)–water	Ambient temperature and slightly elevated pressure	Four consolidated carbonates One unconsolidated carbonate	–
Pentland et al. [40]	Octane–brine	20 °C; 0.101 MPa	Sand packs	–
Pentland et al. [38]	CO_2–water Oil (n-decane)–water	70 °C; 9 MPa	Consolidated Sandstone	Water wet
Krevor et al. [48]	CO_2–Water	50 °C; 9 MPa	Sandstone	Strong water wet system
Suekane and Nguyen [39]	CO_2–Water	45 °C; 8 MPa	Sandstone	–

Table 3 Summary of recent studies attempted to evaluate the relationship between interfacial tension, viscosity and residual CO_2 saturation.

References	Range of IFT	Range of viscosity	Fluids system	Experimental conditions
Bennion and Bachu [42]	19.8–56.2 (mN/m)	0.014–0.075 (MPa)	CO_2–brine	43 °C and 200–2900 psi
Wildenschild et al. [31]	17–72 (dynes/cm)	0.018–4.82 (cP)	System 1: non wetting types: air, octane and Soltrol 220 Wetting: brine	21–22 °C and 1 atm
	37–72 (dynes/cm)	1.13 for each	System 2: wetting: Triton 1, Triton 2, Triton 3, Triton 4, Triton 5 and Triton 6, Glycerol 1, Glycerol 2 Non wetting: air	
Harper [43]	25–50 (dynes/cm)	0.025–0.15	System 1: non wetting: air, octane and Soltrol 220 Wetting: brine System 2: wetting: Triton 1, Triton 2, Glycerol 1, Glycerol 2 Non wetting: air	22 °C and 1 atm

Table 4 Summary of studies carried out on contact angle variation under different conditions.

References	System under study	Experimental conditions
Chiquet et al. [61]	CO_2–brine–quartz or mica	UP to 11 Mpa and ambient temperature
Shah et al. [62]	CO_2 or H_2S–brine–mica, quartz and caprock	Up to 15 MPa; 35 °C and 70 °C
Jung and Wan [63]	CO_2–brine–silica	0.1–25 MPa; 45 °C
Farokhpoor et al. [57]	CO_2–brine–mica/quartz/calcite/feldspar	Up to 40 MPa; 36 °C and 66 °C
Li and Fan [64]	CO_2–brine–glass CO_2–brine–FEP	Up to 10 MPa; 20 and 40 °C

*FEP: fluorinated ethylene propylene

saturation increases with a decrease in porosity of samples having larger pore-throat aspect ratio. Pentland et al. (2012) predicted characteristics of a porous medium through image analysis. They stated that relationship between porosity and residual CO_2 saturation would be different for unconsolidated mediums. They also observed a week relationship between permeability and residual CO_2 saturation [54]. A number of researchers have also investigated the relationship between porosity and residual CO_2 saturation. They similarly concluded that the residual CO_2 saturation increases with a decrease in porosity in storage medium [23,28,53].

According to Tanino and Blunt (2012), as pore coordination number (quantitative connectivity of pore throats to pore system) increases, residual CO_2 saturation decreases [36]. Cense and Berg (2009) indicated that residual saturation begins to decline at a critical capillary number of 10^{-5} and 10^{-3} for non-wetting and wetting phases respectively [66]. Through direct observation of trapped gas bubbles in Berea sandstone, it was also found that capillary number governs the stability of trapped gas bubbles [29]. For example, Morrow et al. (1988) reported that trapped non-wetting phase saturation for consolidated sandstone decreases at any capillary number bigger than 10^{-6} [70]. In one of the recent studies carried out through X-ray micro-computer-tomography experiments to understand the capillary trapping mechanism of gas bubbles, it was found that there is a systematic dependency between trapping efficiency and capillary number at 2×10^{-7}–10^{-6} [71], which denied the earlier statement indicating the inverse relationship between capillary number and residual CO_2 saturation [37].

Flow rate is another parameter found to be linked to capillary trapping and residual CO_2 saturation [72]. In fact, recent studies stated high injection rates suppress the snap-off process and result in low residual CO_2 saturation [31,73]. Soroush et al. (2013) found the sensitivity of residual CO_2 saturation with the imbibition rate if rock has less wettability in its wetting phase [58]. Shamshiri and Jafarpour (2012) also stated that capillary trapping can be optimized by controlling the injection rate [26]. Table 5 gives an overview of capillary pressure measurements performed in recent years at a particular capillary number.

There are very few studies to date brining a discussion on the relationship between pore pressure and non-wetting phase saturation. Saeedi et al. (2012) carried out experiments on brine saturated sandstone to test the effect of stress variation on capillary trapping. They indicated that changes in effective pressure due to an increase in overburden stress at a constant injection rate improve CO_2 entrapment. They also found that changes in pore pressure decrease the residual CO_2 saturation at a constant overburden stress [67]. According to Lamy et al. (2010), an increase in non-wetting phase pressure affects the pore structure of carbonates and, therefore, the initial oil saturation decreases after reaching a maximum value [23].

There have been studies considering multiphase systems to govern the effect of natural residual gas on the residual CO_2 saturation. For instance, Al Mansoori (2009) noticed that

Table 5 Summary of recent studies carried out on capillary trapping measurements at a particular capillary number.

References	Measurements	Experimental conditions	Rock	Capillary number
Mansoori et al. [47]	Capillary trapping	20 °C; 0.101 MPa	Unconsolidated sand packs	1×10^{-5}–2×10^{-6}
Lamy et al. [23]	Capillary trapping	Ambient temperature and slightly elevated pressure	Consolidated carbonates Unconsolidated carbonate	$< 8 \times 10^{-7}$
Pentland et al. [40]	Capillary trapping	20 °C; 0.101 MPa	Sand packs	2.66×10^{-7} 2.66×10^{-6} 5.66×10^{-6}
Wildenschild et al. [31]	Capillary trapping	21–22 °C; 1 atm	Sintered glass bead pack	10^{-8}–10^{-6}
Pentland et al. [38]	Capillary trapping	70 °C; 9 MPa	Sandstone	4.1×10^{-7}
Krevor et al. [48]	Capillary trapping Relative permeability	50 °C; 9 MPa	Sandstone	10^{-8}–10^{-7}
Tanino and Blunt [36]	Capillary trapping	20 °C; 0.101 MPa	Sandstone and limestone	1.1×10^{-6}
Saeedi and Rezaee [51]	Injectivity and capillary trapping	83 °C; 17.78 MPa	Sandstone	$2.65 * 10^{-6}$–$9.65 * 10^{-5}$
Suekane and Nguyen [39]	Capillary trapping	45 °C;8 MPa	Sandstone	4.8×10^{-6}
Harper [43]	Capillary trapping	22 °C; 0.101 MPa	Two sintered, soda lime glass bead columns	10^{-3}–10^{-6} (based on secondary imbibition)

trapped gas quantity of a multiphase system and that of a two-phase system are similar [6]. Another study in this field of research indicated that naturally trapped saturation only affects injectivity and may not have any influence on CO_2 entrapment due to replacement of natural residual gas by CO_2 in injection cycles [51].

3. Summary

In this paper a review on capillary trapping and its relative effective parameters was presented. It is known that capillary trapping is a rapid and effective mechanism due to the snap-off process, specifically in strong water wet and quartz-rich sandstone formations. Therefore, it is vital to determine the capillary trapping ability of storage medium since it controls the long-term fate of CO_2 storage.

There are many parameters indicated to have positive or negative impacts on capillary trapping so it is recommended to perform integrating study for the determination of major and minor factors affecting capillary trapping in any storage medium. However, since many of recent studies carried out on CO_2 storage were considered a two-phase system, it would be helpful to perform measurements in a three phase system to properly understand the capillary trapping in depleted hydrocarbon reservoir. It is also recommended to do some studies on the variation of wettability with pressure as it is yet to be fully understood.

Acknowledgment

This work is supported by Curtin Sarawak University, Malaysia through the Curtin Sarawak Research Institute (CSRI) Flagship scheme.

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