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CO_2 Enhanced Oil Recovery in Heterogeneous Porous Media: An Experimental Investigation

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Author's Declaration

To the best of my knowledge and belief this thesis contains no material previously published by any other person except where due acknowledgment has been made.

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Abstract

Many experimental and numerical simulation studies, as well as field-scale applications, have demonstrated the CO_2 flooding to be a promising enhanced oil recovery (EOR) technique. In addition, CO_2 enhanced oil recovery (CO_2-EOR) has the potential to make a measurable contribution towards mitigating the global warming phenomenon by geo-sequestration of the greenhouse gases. On the other hand, CO_2-EOR is known to suffer from a number of inherent technical uncertainties associated with unstable nature of the in-situ displacement. The flood instabilities are often caused by the high mobility of injected CO_2 and, to a lesser extent, its lower density compared with the resident crude oil. It is also a known fact that the heterogeneous nature of hydrocarbon reservoirs would intensify the negative effects of such deficiencies with the potential of making the EOR technique technically and economically unfeasible. Of the many laboratory studies conducted to date to evaluate the performance of CO_2-EOR, very few have focused on determining the effects of heterogeneity on recovery profile utilising a systematic and reproducible technique. Even the very limited studies that feature the above often fall short of quantifying the contribution of critical factors such as interlayer crossflow, flooding scheme (e.g. continuous CO_2 injection vs. WAG flood), flooding mode (i.e. tertiary vs. secondary injection) and/or miscibility conditions on their reported outcomes. Hence, this study was initiated to address the above-identified gaps in knowledge.

In this research, core flooding experiments were conducted under elevated temperature and pressure. While all experiments were conducted under a fixed temperature of 343K, two pressure values of 9.6 MPa and 17.2 MPa were utilised to provide immiscible and miscible flooding conditions, respectively. The experimental fluid comprised of a synthetic brine, *n*-Decane and high purity CO_2. The heterogeneous sandstone samples were carefully manufactured using originally homogenous cores to create samples with either axial (i.e. composite samples) or radial (i.e. layered samples) heterogeneity. In the layered samples, interlayer communication was controlled by the insertion of an impermeable Teflon sheet or a water-wet permeable tissue paper in-between their two layers (i.e. half plugs). A limited number of flooding experiments were also monitored in real-time using an X-ray computed tomography (X-ray CT) scanner to generate invaluable visual evidence of suspected in-situ phenomena taking place during flooding.

As a high-level observation, this study confirmed the noticeable channelling of injected CO_2 in layered samples through their high permeability layer affecting the oil recovery factor (RF) negatively. The channelling was found to be intensified with

increasing the permeability ratio (PR) between the sample layers. For example, the ultimate oil recovery decreased by 18.0% with changing PR from 2.5 to 12.5. Furthermore, not only miscible flooding ($RF_{PR12.5}$= 69.8%) resulted in significantly higher recovery than immiscible ($RF_{PR12.5}$= 54.7%) but also the permeability contrast was determined to have a more pronounced effect on recovery under immiscible conditions than miscible. This was mainly attributed to the capillary forces dominating the flow under immiscible conditions making the influence of permeability heterogeneity more pronounced. In general, the dependence of recovery profile on heterogeneity was found to be much more subtle in composite cores, in all cases and scenarios investigated. This was mainly due to the absence of a preferential flow path in the direction of the flood in these samples.

The experiments revealed that WAG flooding scheme would help to suppress the pronounced effects of heterogeneity as observed during continuous CO_2 injections. For instance, under PR=12.5 and miscible conditions the WAG flood improved the RF by 4.2%. Furthermore, while the interlayer crossflow was found to enhance the oil recovery during continuous miscible CO_2 flooding by 1.8% (for PR=12.5), intriguingly, an opposite trend was observed during miscible WAG flooding (e.g. decrease of 6.6% under PR=12.5). Such an effect is believed to be caused by the reinforcement of the influence of viscous forces in the absence of crossflow during WAG flooding leading to higher oil recovery. The results obtained from another set of the core flooding tests demonstrated the importance of early application of CO_2 flooding via the secondary mode. This would help to avoid the deteriorating effects of water shielding problem arising when a tertiary flooding mode is utilised. The water shielding would impede the access of the injected CO_2 to some of the otherwise recoverable oil. For example, for the continuous miscible CO_2 injection case, the secondary flooding mode resulted in a 6.4% additional recovery under PR=5.

The X-ray CT monitored experiments conducted on layered samples provided insightful visual images to reveal that core-scale heterogeneity would play a significant role in dictating the spatial distribution of injected CO_2 during flooding and hence the recovery profile. The spatial fluid distributions were found to be correlated reasonably well with the permeability of each layer. The X-ray images clearly showed the channelling of injected CO_2 through the high permeability layer leading to a considerable amount of oil bypassed in the low permeability one. Moreover, a closer analysis of the images confirmed the occurrence of crossflow in layered cores suggesting that capillarity plays a noticeable role in increasing oil recovery during continuous CO_2 injection. Furthermore, the CO_2 diverted into the low permeability layer due to crossflow was found to be trapped there by associated trapping mechanisms.

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List of publications included as part of the thesis

Parts of this thesis have been published in the following articles:

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2. Duraid Al-Bayati, Ali Saeedi, Mathew Myers, Cameron White & Quan Xie. 2018, An Experimental Investigation of Immiscible CO_2 Flooding Efficiency in Sandstone Reservoirs: Influence of Permeability Heterogeneity. SPE Reservoir Evaluation & Engineering, Preprint, 8. https://doi.org/10.2118/190876-PA

3. Duraid Al-Bayati, Ali Saeedi, Mathew Myers, Cameron White & Quan Xie. 2019, Insights into immiscible supercritical CO_2 EOR: An XCT scanner assisted flow behaviour in layered sandstone porous media. Journal of CO_2 Utilization, 32, 187-195. http://www.sciencedirect.com/science/article/pii/S2212982018309247

4. Duraid Al-Bayati, Ali Saeedi, Mathew Myers, Cameron White, Quan Xie & Ben Clennell. 2018, Insight investigation of miscible $_{SC}CO_2$ Water Alternating Gas (WAG) injection performance in heterogeneous sandstone reservoirs. Journal of CO_2 Utilization, 28, 255-263. https://doi.org/10.1016/j.jcou.2018.10.010

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I warrant that I have summarised and identified, where necessary, the contribution of each of the co-Authors in the listed publications above and attached to the Appendices and hereby I have signed.

Candidate: Duraid Mohammed Attieya Al-bayati

Supervisor: Ali Saeedi

List of additional publications by the candidate relevant to the thesis but not forming part of it

1. Duraid Al-Bayati, Ali Saeedi, Ipek Ktao, Mathew Myers, Cameron White, and Quan Xie. “A Coupled Experimental and Simulation Investigations of Miscible WAG Flooding Performance in Cross bedded Sandstone Reservoirs.” One Curtin International Postgraduate Conference (OCPC) 2018 Miri, Sarawak, Malaysia, November 26 – 28, 2018.

2. Duraid Al-Bayati, Ali Saeedi, Mathew Myers, Cameron White, and Quan Xie. “An Experimental Investigation of Immiscible CO2 Flooding Efficiency in Sandstone Reservoirs: Influence of Permeability Heterogeneity.” SPE Europec featured at 80th EAGE Annual Conference & Exhibition held in Copenhagen, Denmark, 11-14 June 2018.

3. Duraid Al-Bayati, Cameron White, Quan Xie, Mathew Myers, and Ali Saeedi. “Effect of Crossflow and Heterogeneity on CO2 Behaviour in Sandstone Oil Reservoirs.” 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14, Melbourne, Australia, 21st-25th October 2018.

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5. Duraid Al-Bayati, Ali Saeedi, Cameron White, Quan Xie & Mathew Myers. “The Effects of Crossflow and Permeability Variation on Different Miscible CO2 injection Schemes Performance in Layered Sandstone Porous Media”. IOR 2019–20th European Symposium on Improved Oil Recovery, 8-11 April 2019 Pau, France. EarthDoc.

6. Duraid Al-Bayati, Ali Saeedi, Ipek Ktao, Eghan Arjomand, Mathew Myers, Cameron White & Quan Xie. “Insight into Influence of Crossflow in Layered Sandstone Porous Media during Miscible and Immiscible CO2 WAG Flooding”. INTERPORE, 6-10 May 2019 Valencia, Spain.

7. Duraid Al-Bayati, Ali Saeedi, Mohsen Ghasemi, Eghan Arjomand, Mathew Myers, Cameron White, and Quan Xie. 2019. “Evaluation of Miscible CO WAG/Sandstone Interactions: Emphasis on the Effect of Permeability” Heterogeneity and Clay Mineral Content. SPE Europec featured at 81st EAGE Conference and Exhibition. London, England, UK: Society of Petroleum Engineers.

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Chapter 1

1.1 Introduction

The progress of enhanced oil recovery (EOR) processes are often hampered by technical, operational and economic challenges. One well-recognised example of such challenges is the presence of the naturally occurring formation heterogeneities in a reservoir system (Jaber et al., 2017a, Park et al., 2017, Zhao et al., 2017). A major objective of this research is to experimentally investigate how heterogeneity may impact on the outcome of a CO_2 enhanced oil recovery process (CO_2-EOR) under various injection schemes and modes (e.g. continuous vs. alternating injection, secondary vs. tertiary flooding) and flooding conditions (e.g. miscible vs. immiscible injection).

This chapter aims to present a brief background to this research, provide a short description of the problem this work is to tackle followed by an outline of the main objectives pursued. Finally, this chapter will provide a short overview of how various chapters/sections of this thesis are organised.

1.2 Background and Problem Description

Enhanced Oil Recovery (EOR) projects would normally require significant investment and long operational time (typically several decades) signifying the necessity of having a comprehensive project plan in place. From a technical perspective, the planning may need to address laboratory testing, simulation studies, processing plants, drilling and commissioning, abandonment and decommissioning and more. As such, accurate prediction of the costs and revenues associated with such projects would probably become the most important information considered in the decision-making process. In doing so, a critically important technical information is often an estimation of the incremental oil recovery achievable from a project. The overestimation of this figure may lead to investment loss while its underestimation can cause loss of resources. On the other hand, environmental aspects of such projects have also been the subject of many scrutinies sometimes resulting in passing of regulations limiting the application of certain production enhancement/optimisation techniques. Therefore, an EOR technique that not only has the potential to yield reasonable additional recovery but also can be implemented with low cost and neutral or even positive environmental effects would be highly desirable.

In the past several decades, CO_2 flooding has emerged as one of the most promising EOR techniques applicable in oil reservoirs due to its realistic economic viability and potential environmental benefits (Whorton and Kieschnick, 1950, Whorton et al., 1952, Holm, 1959, Holm and Josendal, 1974, Khatib et al., 1981, Klins and Ali, 1981, Holm, 1982, Orr Jr et al., 1982a, Orr Jr et al., 1982b, Stalkup Jr, 1983, Orr and Taber, 1984, Haskin and Alston, 1989, Mungan, 1991, Rojas et al., 1991, Hadlow, 1992, Blunt et al., 1993, Lindeberg and Holt, 1994, Srivastava et al., 1994, Tortopidis, 1994, Alkemade, 1995, Remenyi et al., 1995, Ring and Smith, 1995, Grigg and Schechter, 1997, Bachu et al., 2000, Jeschke et al., 2000, van Bergen et al., 2004, Gozalpour et al., 2005, Izgec et al., 2005, Manrique et al., 2006, Jie-cheng et al., 2008, Ghedan, 2009, Liang et al., 2009, Salem and Moawad, 2013, Zhao et al., 2014, Cooney et al., 2015, Merchant, 2015, Yanjie et al., 2015, Jaber et al., 2017b, Moghadasi et al., 2018). Such an optimistic outlook is boosted by the fact that depleted hydrocarbon reservoirs offer proven containment and storage integrity for permanent CO_2 storage (Wang et al., 2018). In addition, a relatively high additional oil recovery could offset the cost of the CO_2 injection in such sites. In 1972, one of the earliest cases of CO_2 injection into subsurface geological formations was implemented in Texas, USA, as part of a CO_2-EOR project (Kane, 1979) and such an application has been ongoing there and many other locations ever since (Robie et al., 1995, Remenyi et al., 1995, Burrowes and Gilboy, 2001, Novosel, 2005, Guedes, 2008).

Despite the historical success of CO_2-EOR processes, such displacements are often prone to poor flood conformance mainly caused by the high mobility of the injected CO_2 leading to viscous fingering and, to a lesser extent, the density contrast between the displacing and displaced fluids resulting in gravity override (Spence and Watkins, 1980, Lescure and Claridge, 1986, Araktingi and Orr, 1990, Wylie and Mohanty, 1997, Bahralolom et al., 1988, Homsy, 1987, Araktingi and Orr Jr, 1993, Tchelepi and Orr Jr, 1994). Adding to the complexity of the EOR process is that the reservoir fluids are known to be composed of complex multi-component mixtures giving rise to potentially complex mass transfer phenomena between the in-situ fluids and injected CO_2 (Perkins and Johnston, 1963, Wheat and Dawe, 1988, Burger and Mohanty, 1997, AlHamdan et al., 2011, Salibindla et al., 2018). Such phenomena impact on critical flood characteristics such as the miscibility, breakthrough time and displacement profile. In addition, the majority of reservoirs are naturally heterogeneous to a varying extent. This has a significant impact on the nature and efficiency of the fluid displacement taking place in these reservoirs (Spence and Watkins, 1980, Sorbie et al., 1987, Bahralolom et al., 1988, Araktingi and Orr, 1990, Bahralolom and Heller, 1992, Pande and Orr, 1994, Yaghoobi and Heller, 1996, Yaghoobi et al., 1996, Drid and Tiab, 2004, Al Wahaibi and Al Hadhrami, 2011, Lee, 2011, Higgs et al., 2013, Zhang et al., 2013, Wright and Dawe, 2016, Liang et al., 2019, Oh et al., 2019, Al-Bayati et al., 2019). For instance, when a gas is injected to displace oil, it prefers to follow any existing preferential flow paths (high-permeability layers, zones with natural fractures, etc.) causing highly pronounced flood conformance issues leading to early breakthrough at producing wells (Bahralolom et al., 1988, Zhou et al., 2017, Grigg et al., 1997, Al Wahaibi and Al Hadhrami, 2011). This would, in turn, result in low additional oil recovery and a significant increase in the amount of gas required to recover a certain incremental volume of oil. In fact, reservoir heterogeneity has the potential to significantly amplify the earlier mentioned phenomena of viscous fingering and gravity override. Nevertheless, the conditions of a CO_2 displacement process can be engineered in a way that the severity of the above mentioned operational and technical challenges may be reduced by favourably manipulating the flood's associated displacement mechanisms (i.e. viscous, gravity and capillarity). For instance, laboratory testing, numerical modelling and occasional field-scale applications have revealed that CO_2 foam flooding or injection of CO_2 in alternation with water (water-alternating-gas (WAG) flooding) can help to reduce the severity of viscous fingering and possibly gravity override (Tanzil et al., 2000, Li et al., 2010, Conn et al., 2014, Singh and Mohanty, 2017, Drid and Tiab, 2004, Ding et al., 2017, Jaber et al., 2017a).

To date, there have been many numerical studies conducted evaluating the effects of heterogeneity on oil recovery and how changing the flooding conditions and injection scheme may help to reduce the severity of such negative effects (Furtado and Pereira, 2003, Eaton, 2006, Ahmed Elfeel et al., 2013, Kuo and Benson, 2015, Li et al., 2017, Zhao et al., 2018, Pande and Orr, 1994, Tungdumrongsub and Muggeridge, 2010, Rashid et al., 2012, Dawe and Grattoni, 2008). However, experimental research work evaluating the same are very scarce. Moreover, the few existing works fall short on qualitatively and/or quantitatively evaluating the role of a number of critical contributing factors, such as inter-layer crossflow, miscibility conditions, the orientation of heterogeneity and the flooding mode (secondary vs. tertiary), under various flooding schemes (continuous vs. WAG). To bridge the above-identified gaps in the knowledge, the current research has been designed in a way that it would address the complexities involved in the prediction of oil recovery profile for a CO_2-EOR process conducted in heterogeneous media. Such an investigation would be implemented under various CO_2 injection schemes and modes (e.g. continuous vs. alternating injection, secondary vs. tertiary flooding) as well as miscibility conditions using a set of systematically manufactured heterogeneous porous media under the laboratory scale.

1.3 Research Objectives

The primary purpose of this section is to provide information on the specific objectives pursued by this research work. However, first, a brief description of the particular methodological features, which make the current research to stand out of the few previous closely related works, will be provided. This would not only provide an early background about the chosen research methodology (as addressed in later chapters) but also help with putting the objectives outlined below in context.

To address the earlier outlined gaps in the knowledge about the effects of rock heterogeneity on CO_2-EOR, an extensive and specially designed core flooding program was provisioned for this work. Accordingly, this program was to be conducted under elevated pressure and temperature under various flooding schemes, modes and miscibility conditions and with varying heterogeneity levels on some carefully manufactured heterogeneous sandstone core samples. Sandstone formations constitute many of the world’s giant petroleum reservoirs, making them likely candidates for CO_2 injection for both purposes of storage and EOR. Besides, due to the much less reactivity of their rock formation and reduced complexities associated with fluid-rock interactions, such reservoirs may be preferred for CO_2-EOR processes over their carbonate counterparts (Qi et al., 2009, Krevor et al., 2012). A systematic approach was designed to manufacture heterogeneous core plugs using initially homogenous samples. This technique was believed to make it possible to prepare reproducible samples with predetermined levels of heterogeneity in both vertical (layered samples) and horizontal (composite samples) directions. In addition, in the manufactured layered samples, the cross-layer communication was to be controlled using appropriate barrier material inserted in between the sample layers. Furthermore, in addition to a traditional benchtop core flooding setup, a second setup equipped with an X-ray CT (computed tomography) scanner was provisioned. The use of this setup was expected to result in the generation and collection of insightful X-ray CT images with the potential of shedding light on some of the particular results obtained from the un-imaged traditional flooding setup.

The collection and then accurate analysis of the data and information resulted from the above core flooding program was believed to be the key for establishing a laboratory-scale benchmark for CO_2-EOR design in heterogeneous porous media. Furthermore, it could help to improve the way flooding efficiency might be improved in terms of optimising the injection scheme and mode in the face of varying degree of heterogeneity. In particular, the above would allow to logically and systematically explore the dominant displacement mechanisms influencing the displacement efficiency under various flooding conditions and how they may be manipulated towards achieving a desirable recovery profile.

In light of the above brief description of the planned research work, the main objectives pursued by this research can be summarised as follows. It is worth noting that the below-listed objectives have all been defined in the context of CO_2-EOR.

1. To evaluate how the degree of heterogeneity in the form of permeability contrast perpendicular to flow may influence recovery profile and ultimate recovery of the EOR process in a two-layer system.

2. To investigate how the nature and distribution of permeability heterogeneity in the direction of the flood may control the displacement efficiency and final recovery.

3. To determine how the EOR injection mode (secondary vs. tertiary) may influence the recovery process in heterogeneous porous media.

4. To compare the performance of CO_2 injection using a WAG approach to that of the continuous injection scheme when applied in heterogeneous porous media.

5. To determine the effects that miscibility conditions may have on enhanced recovery in heterogeneous porous media when conducted using the two injection schemes of continuous and WAG.

6. To investigate the contribution of highly regarded cross-flow phenomenon in layered porous media during the EOR process.

7. To study and investigate the effects of other multiphase flow phenomena (e.g. gravity override) on recovery from heterogeneous media.

8. To generate and use X-ray CT images to visually validate some of the multiphase flow phenomena/features (e.g. crossflow) whose effects were evaluated using the conventional un-imaged core flooding procedure.

1.4 Organisation of Thesis

This thesis consists of seven chapters including the current chapter which is to set the scene by providing a brief research background and problem statement, list of objectives and a short outline of the thesis contents. Chapter 2 presents a literature review on EOR processes with the main focus being on CO_2-EOR. This chapter provides information on various aspects and, in particular, the benefits and challenges associated with this EOR process. As the main focus of this research, towards the end of Chapter 2, special attention is given to the studies conducted to date on heterogeneous porous media. Chapter 3, 4, 5 and 6 include the outcomes of this research on the performance of immiscible and miscible continuous CO_2 displacement in heterogeneous porous media followed by similar results for immiscible and miscible WAG flooding. Presented in the form of actual reprints of published scholarly work, these chapters each provide details of the experimental setup used and the experimental procedures followed in conducting various experiments. Besides, they include comprehensive coverage of the relevant results, interpretations and discussions. Finally, Chapter 7 provides a brief summary of the research work as a whole with a condensed list of main conclusions followed by recommendations for any future work.

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Chapter 2

2.1 Introduction

Traditionally, oil recovery processes may be divided into three stages of primary, secondary, and tertiary (Figure 1). Historically, these stages cover the production from a reservoir in chronological order. Primary production or the initial production stage results from the natural displacement energy existing in a reservoir; the driving energy may come from the expansion of a gas cap or an active aquifer, the liberation and expansion of dissolved gas, gravity drainage, or a combination of some of these mechanisms. Secondary recovery or the second stage of the recovery process is usually implemented once the primary recovery mechanism(s) begins to decline. Conventionally used secondary production processes may include gas injection and water flooding when they are done as a means of pressure maintenance or displacing the oil without changing the intrinsic properties of the in-situ fluid-rock system (e.g. fluid viscosity, rock wettability, etc.). The laboratory and, most importantly, filed data indicate that the primary and secondary stages may only recover up to 20-40% of the original oil in place (OOIP) (Tunio et al., 2011, Atia and Mohammedi, 2018), although in some cases, recoveries could be lower or higher (Stalkup, 1983, Tzimas et al., 2005). Tertiary or enhanced oil recovery (EOR) is a term used to describe a set of processes intended to increase the production of oil beyond what could normally be extracted after the implementation of the primary and secondary production stages. Similar to a secondary recovery process, EOR would also involve the introduction of a foreign fluid/injectant into the reservoir, however, in EOR the additional recovery result from some favourable change in the in-situ properties of the fluid-rock system. For example, gas injection would be considered an EOR process if the injected gas dissolves in the oil resulting in a decrease in the interfacial tension (IFT) and viscosity of resident crude oil. The utilisation of EOR processes may yield an additional 20-25% recovery of the OOIP (Lake, 1989a, Tunio et al., 2011).

Given the declining curve in the discovery of new oil reserves and the ever-growing global demand for energy, there is an urge felt for boosting production from existing oil fields many of which already have or about to reach their maturity (Lake, 1989b). An EOR technique could result in a favourable outcome if it is designed to be compatible with the particulars of the target oil field. In other words, there is no single EOR method that could fit all reservoirs. The screening and possible optimisation efforts conducted to turn an EOR operation into reality for a field would need to address technical, environmental, regulatory, economic, etc. factors. As indicated in the previous chapter, the objective of this research work has been to revisit the favourable CO_2-EOR technique and put its application into test in the context of heterogeneous porous media using a systematic experimental approach. To achieve the above, the effects of a number of important operational (e.g. injection scheme/mode) and geological (e.g. degree of heterogeneity, cross-layer communication, etc.) factors on the outcome of the experimental work have been evaluated.

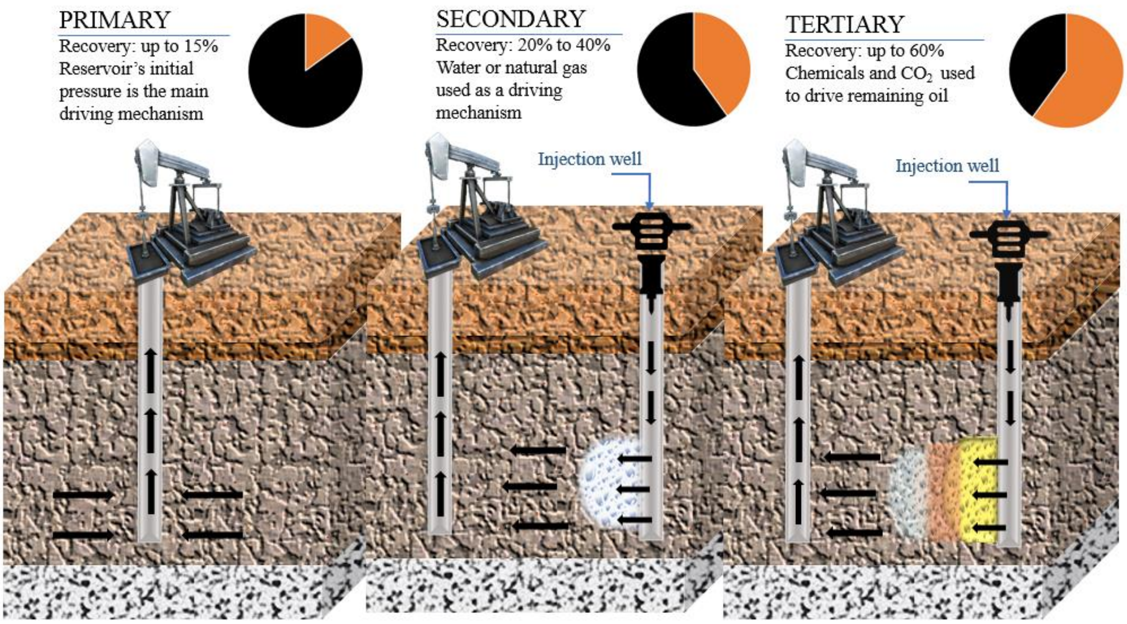

Figure 1. Different stages of oil recovery (Primary, secondary and tertiary).

Since this dissertation is submitted using the 'Thesis by Publication' option, the purpose of this chapter is not to provide a detailed literature review on the research topic at hand. It rather is going to put the upcoming chapters of the dissertation that are mainly composed of published journal manuscripts into context. Therefore, this chapter mainly provides a background to the technical factors and features that may impact on the efficiency of CO_2-EOR with a special focus on heterogeneous porous media as investigated in the current research. It is worth noting that the manuscripts forming the remaining chapters of the dissertation still each includes a detailed review of the relevant literature.

2.2 Enhanced Oil Recovery Methods

Many EOR methods have been used in the past with varying degrees of success for the recovery of light to heavy oils as well as tar sands. However, these methods may be broadly divided into the two major categories of thermal and non-thermal methods (includes gas and chemical methods) (Selby et al., 1989). Each of these two main categories encompasses a number of individual EOR processes (Thomas, 2008) some of which will be defined and briefly described below.

Thermal methods are primarily intended for heavy oils and tar sands; these methods recover the oil by introducing heat into the reservoir (Lake, 1989b, Thomas, 2008, Alvarado and Manrique, 2010). A thermal method is based on a set of displacement mechanisms to enhance oil recovery with the most important mechanism being the reduction of crude oil viscosity with increasing temperature. However, the viscosity reduction is less for lighter crude oils whose initial viscosity is already relatively low. Therefore, thermal methods have had limited success in the fields containing such crude oils.

Non-thermal methods (include improved water recovery, polymer flooding, surfactant, caustic and other chemical flooding, immiscible/miscible gas flooding, solvent flooding, etc.) may normally be used for relatively lighter oils ($< 100\ cp$). However, Selby et al. (1989) reviewed 113 field tests in addition to some data from laboratory experiments to evaluate the potential of non-thermal methods for heavy oil recovery ($< 2000\ cp$). Upon the completion of their study, they signalled the possible success of these methods in such fields with some restrictive conditions. In chemical methods that involve injection of polymers, surfactants, alkalines, and foams in some form (Lake, 1989b, Liu, 2008), the main effective mechanisms sought to depend on the nature of the chemical additive introduced into a reservoir. However, in general, these methods may provide one or several of the following effects (Thomas, 2008): IFT reduction, oil viscosity reduction, wettability alteration, and mobility control. Another type of non-thermal methods is the immiscible/miscible gas injection during which gases such as natural gas or CO_2 may be used to enhance oil recovery (Thomas, 2008). The effective mechanisms underpinning this type of EOR process are to some extent similar to those named for chemical flooding. Gas injection, particularly CO_2, could be very successful method especially for the reservoirs with low permeability, high pressure, and lighter oil (Mungan, 1981, Rivas et al., 1994, Jarrell et al., 2002, Ghedan, 2009).

As indicated in a recent report by the International Energy Agency (IEA), thermal methods account for more than 40% of the current global oil yield from EOR methods followed by CO_2-EOR, chemical EOR and other gas injections methods each with about 20% share (Figure 2). The above statistics may be an indication of the effectiveness of CO_2 injection as a popular EOR method. As indicated by IEA in the same report, although the total number of global EOR projects declined sharply in the early 1990s, since then their number has been on the gradual rise again reaching almost 380 projects in 2017.

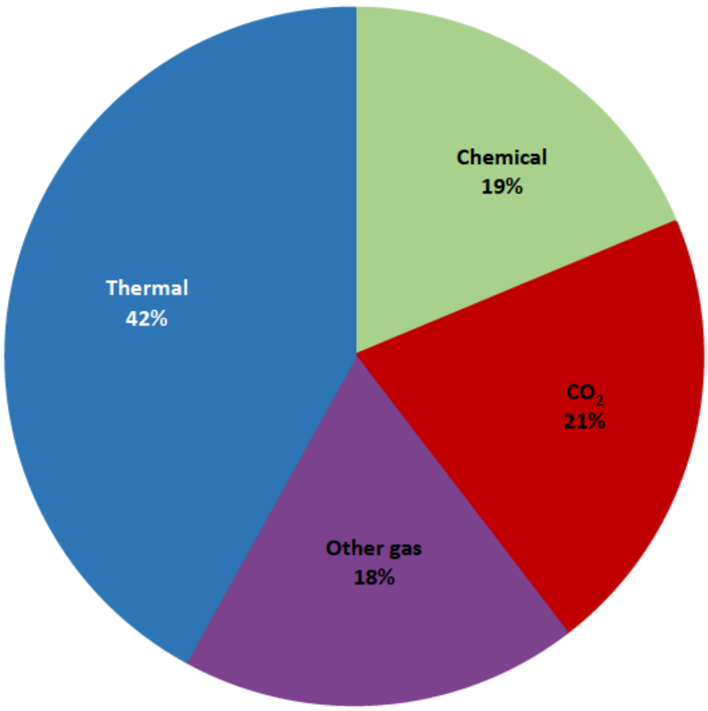

Figure 2. Current contribution of each EOR method to the recovery (Retrieved from (IEA, 2018)).

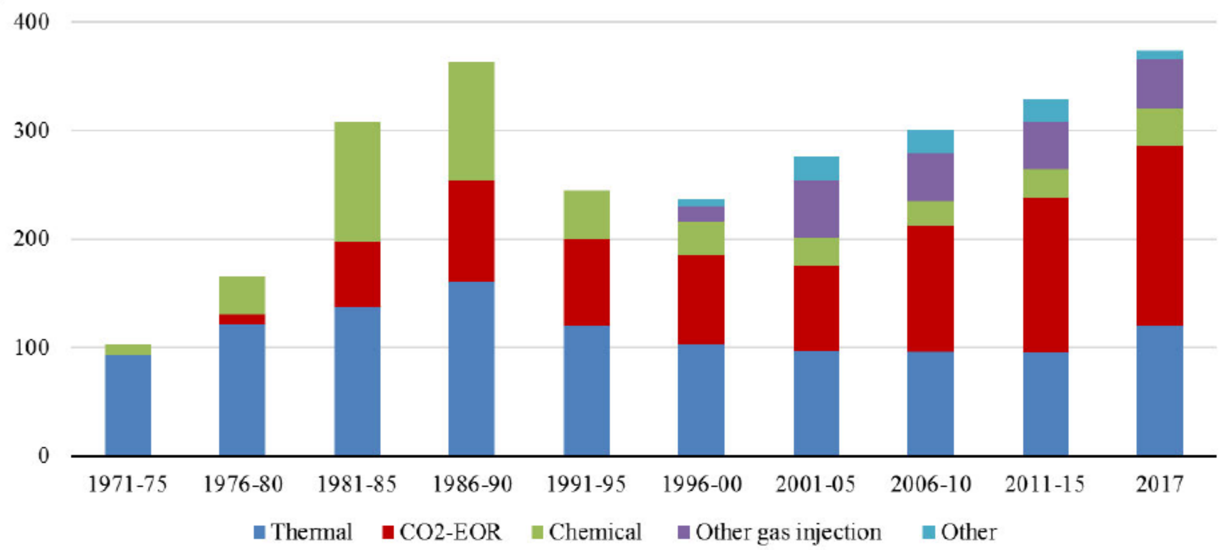

Figure 3. Number of EOR projects in operation globally over the last 40 years (Retrieved from (IEA, 2018))

2.3 Carbon Dioxide Enhanced Oil Recovery

An effective and viable way to considerably reduce CO_2 emissions is to inject the CO_2 captured from major industrial sources into depleted oil reservoirs where the unwanted gas can be used as a displacing fluid for the purpose of EOR. Hence, enhancing oil recovery using CO_2 injection is viewed as an attractive EOR method to produce petroleum substances that would otherwise remain unrecoverable (Whorton and Kieschnick, 1950, Whorton et al., 1952, Holm, 1959). The first successful field implementation of a CO_2-EOR technique to boost oil production from a depleted oil formation was carried out in Kelly-Snyder Field in Texas, U.S., in 1972 (Kane, 1979). Many other applications have since followed in many different oil fields worldwide (Robie et al., 1995). For example, in 2005 a pilot CO_2 flood was performed at Ivanic Field in Croatia using CO_2 from industrial sources (Novosel, 2005). In 2008, a number of CO_2 floods were carried out in Rio Pojuca and Mirange fields in Brazil for the dual purpose of EOR and carbon geo-storage (Guedes, 2008). Hungary also has decades of experience in execution of CO_2 flooding projects among which those conducted in Budafa and Lovvaszi fields are well-documented (Remenyi et al., 1995). In addition, several field operators and organizations in Canada have been very active in assessing and implementing CO_2-EOR over the past few decades (Bachu et al., 2000). Two well-known example applications of CO_2-EOR in Canada include those conducted in the Joffre Field in southern Alberta and the Weyburn Field in Midale, Saskatchewan (Burrowes and Gilboy, 2001).

As indicated earlier, typically, only 20-40% of the original oil in place (OOIP) may be produced after the primary and secondary recovery stages. A large amount of the remaining oil is trapped by capillary forces as disconnected blobs and ganglia, surrounded by water. Often oil is also left behind in bypassed zones that are caused by the presence of some form of heterogeneity in the reservoir or uneven flooding (e.g. gravity override). Various schemes of CO_2 injection (e.g. continuous or alternating injection) conducted under various miscibility conditions may help with recovering oil trapped in any of the above-mentioned forms. The miscible CO_2 flooding may lead to an incremental recovery of about 10-20% of the OOIP, while the immiscible type may only recover an additional 5-10% (Moritis, 2002).

The low saturation pressure of CO_2 compared to N_2, CH_4 and other hydrocarbon solvents is an incentive for the use of CO_2 or a mixture of hydrocarbon solvents with CO_2.

Furthermore, at the elevated pressure and temperature conditions encountered in a typical oil reservoir, CO_2 would exist in its dense supercritical state ($scCO_2$), which compared to N_2 and natural gas, has a density closer to that of the displaced oil present in the reservoir. This would tend to make CO_2 flooding less prone to gravity segregation (Bui, 2010). In addition, the CO_2 injection is known for its excellent ability to swell oil and reduce its viscosity, reduce IFT of the in-situ fluid system as well as its high solubility in oil (i.e. the ease of achieving miscibility) and water that can have a positive impact on the ultimate oil recovery (Trivedi and Babadali, 2006, Saeedi, 2012, Zhao et al., 2014, Cooney et al., 2015, Kamali et al., 2016, He et al., 2016). In more recent years, the increase in environmental awareness and the desire to cut back on CO_2 emissions have brought about another added advantage to use the unwanted gas in EOR processes. Currently, there are 80 EOR projects involving CO_2 flooding in North America (Thomas, 2008).

The performance of a CO_2 flooding process may be controlled by several operational factors and reservoir properties including the reservoir pressure and temperature, in-situ phase behaviour of the fluid system, capillary pressure, wettability, compositional effects, interfacial tension (IFT), reservoir geology and formation heterogeneity. The potential effects of some of these factors have already been investigated to some extent by several research groups (Yongmao et al., 2004, Pini et al., 2012, Pini et al., 2013, Li et al., 2015, Al Sulaiman et al., 2016, Bikkina et al., 2016, Jiménez-Martínez et al., 2016). However, as discussed in further details in the remainder of this chapter, there are many smaller but critical features regarding the way some of these factors may impact on CO_2 flooding that requires a more systematic experimental scrutiny. Before presenting a discussion on the above, it is important to present an overview of the basic thermodynamic properties of CO_2 and also address the main sweeping mechanisms of a typical CO_2-EOR process at both microscopic and macroscopic scales.

2.3.1 Thermophysical Properties of CO_2

The effectiveness of an EOR operation would to a large extent depend on the particular thermophysical properties of the injected fluid. Therefore, given the focus of this research work, this section aims to present a brief overview of physical properties of CO_2 under typical subsurface conditions where it may be used to displace the in-situ crude during an EOR process.

Carbon dioxide is formed from the combination of two elements of carbon and oxygen. As a natural and crucial component of the atmosphere, CO_2 is a colourless, odourless, non-toxic and stable compound found in its gaseous state at standard conditions (0.1 MPa and 25 °C), with the density and viscosity of 1.98 kg/m^3 and 1.49×10^{-5} Pa.s, respectively (Zondervan et al., 2001). Table 1 provides some basic physical properties of CO_2 with its phase diagram included in Figure 4. As can be seen from this figure, the triple point at which the three possible phases of CO_2 can coexist is located at 0.52 MPa and $-56.56\ °C$. At pressures and temperatures greater than its critical point (7.38 MPa and 31.10 °C), CO_2 would exist in its supercritical state with its unique properties (i.e. having a combination of gas and liquid properties) (Budisa and Schulze-Makuch, 2014). As mentioned earlier, given the conditions encountered in typical hydrocarbon reservoirs, CO_2 is expected to exist in its low viscosity but at dense supercritical state. The variation in the viscosity and density of CO_2 for a range of pressure and temperature conditions is depicted in figures Figure 5 and Figure 6.

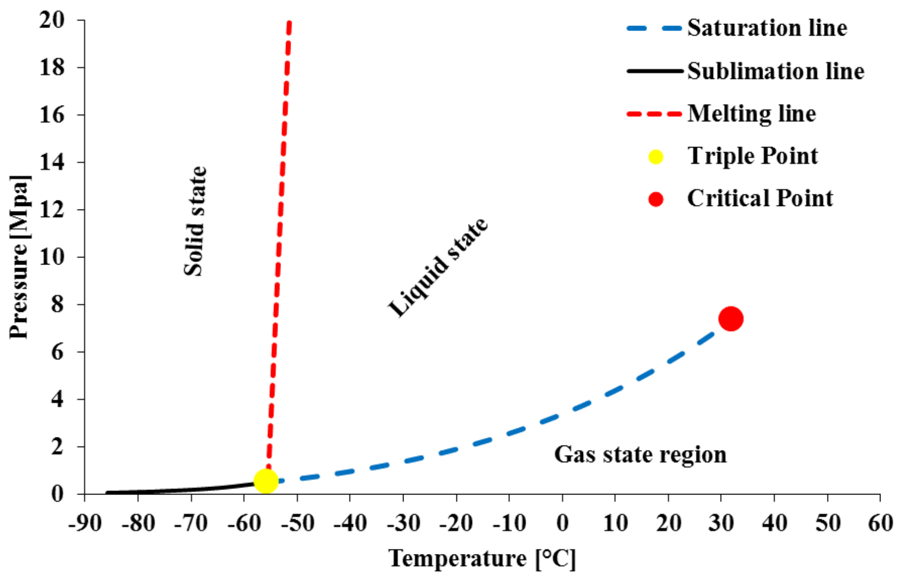

Figure 4. Pressure-Temperature CO_2 phase diagram (data retrieved from (Span and Wagner, 1996)).

Table 1.*Some basic carbon dioxide physical properties (Retrieved from (NIST, 2019))*

Property	Value
Molecular Weight	44 gm/mol
Critical temperature	304.128 K
Critical pressure	7.377 MPa
Critical density	467.6 Kg/m^3

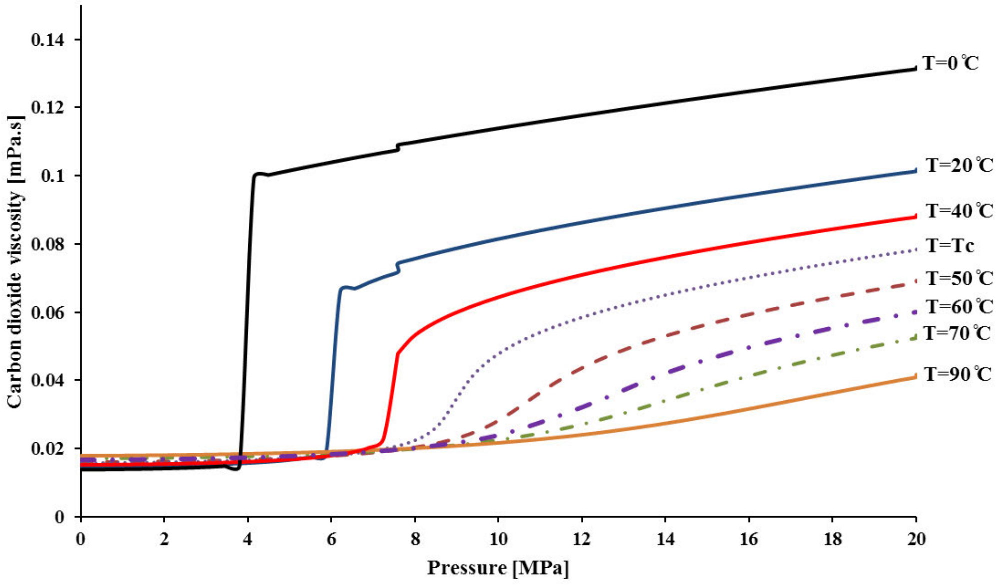

Figure 5. Viscosity of carbon dioxide under various Pressure-Temperature conditions (retrieved from (NIST, 2019)).

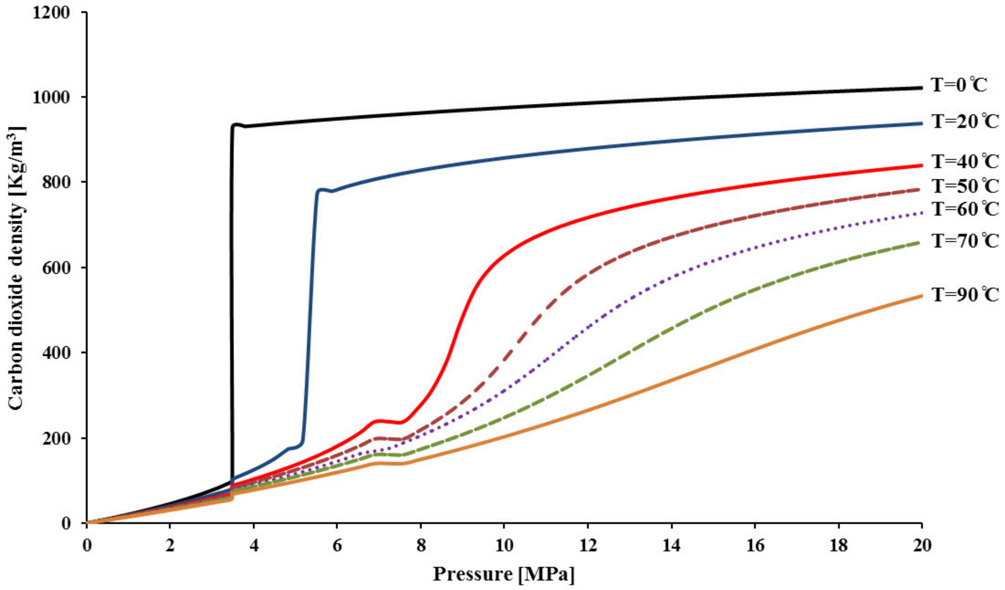

Figure 6. Density of carbon dioxide under various Pressure-Temperature conditions (retrieved from (NIST, 2019)).

2.3.1 Microscopic and Macroscopic Sweep Efficiency

The effectiveness of an EOR technique depends in large part on how it can improve the microscopic and/or macroscopic sweep efficiencies of the residual/in-situ oil (Verma, 2015). The microscopic sweep efficiency (E_D) relates to the displacement of oil by the injected fluid at the pore level. In other words, E_D is controlled by the balance between the forces and mechanisms influencing the displacement at the pore-scale. Such forces in turn are influenced by the reservoir pressure, temperature, in-situ oil composition,

composition and phase behaviour of the injected fluid and the wettability and pore geometry of the rock formation (Sehbi et al., 2001, Meybodi et al., 2011). The macroscopic or volumetric sweep efficiency (E_V), on the other hand, reveals how effectively an injected fluid can contact different parts of a rock formation in horizontal and vertical directions at the much larger reservoir scale. The E_V is dictated to a great extent by the degree of the reservoir-scale heterogeneities present in a formation. The overall sweep efficiency (E) can then be defined using Eq 1 (Ghedan, 2009).

$$E = E_V \times E_D \qquad \text{Eq. 1}$$

One of the most important parameters that influence the macroscopic (areal and vertical) sweep efficiency directly and the microscopic (pore level) sweep efficiency indirectly is the mobility ratio (Thomas, 2008). Mobility ratio is defined as $M = \lambda_{inj}/\lambda_{ed}$, where λ_{inj} is the mobility of the displacing fluid, and λ_{ed} is the mobility of the displaced fluid. The mobility of a fluid in turn is defined as $\lambda = k/\mu$, where k is the effective permeability (m^2) and μ the viscosity (Pa.s) of the fluid concerned. A value of M>1 is considered unfavourable (Thomas, 2008), because it indicates that the displacing fluid is capable of flowing more readily than the displaced fluid. Such a situation in an EOR process can cause fingering and premature breakthrough of the displacing fluid, and as a result, bypassing of some of the oil and undermining the E_V. With the occurrence of the above, more displacing fluid would need to be injected to obtain a given residual oil saturation. Displacement efficiency is improved when $M \leq 1$, which is denoted a 'favourable' mobility ratio (Thomas, 2008). Concerning CO_2-EOR processes, a typical displacement of oil by CO_2 would often suffer from a highly unfavourable mobility ratio mainly due to the special properties of CO_2 under in-situ conditions. The aim of the next section of this chapter is in part to address this issue as well as possible gravity override in further details and also present an overview of possible techniques that could be used to overcome such challenges. How mobility ratio may impact on the microscopic sweep efficiency will be pointed out later when a detailed discussion is presented around the miscibility of the injected CO_2 with in-situ oil and its impact on the flood performance.

2.3.2 Flooding Schemes

A CO_2 flood may be implemented using a simple continuous injection scheme. In this technique, CO_2 is the only fluid injected uninterruptedly to assist with enhancing the oil recovery from a reservoir. However, such a technique is prone to a number of in-situ flood deficiencies negatively impacting on the sweep efficiency of the displacement and potentially undermining its economic and technical feasibility. As indicated earlier, in a typical EOR process, CO_2 would exist in its supercritical state which has a viscosity close to that of its gaseous phase. Therefore, due to the prevailing unfavourable mobility ratio, fingering, channelling and premature breakthrough are expected. In fact, the above phenomena have often been experienced in laboratory experiments and observed in field applications. Furthermore, although $scCO_2$ offers a modest density, gravity segregation may still occur giving rise to negative effects with eventual outcomes similar to those outlined for the unfavourable mobility ratio. It is worth noting that the potential effects of the above-mentioned issues may be further intensified by the presence of any reservoir-scale heterogeneities. The possible effects of reservoir heterogeneity in particular on CO_2 floods are discussed in greater details in later sections of this chapter. There are several techniques proposed in the literature that have been extensively tested in the laboratory and occasionally employed in field applications to combat the inherent displacement deficiencies outlined above. Two prominent examples of such techniques include foam flooding and Water Alternating Gas (WAG) flooding.

Foam flooding is a highly recognized method to mitigate unstable CO_2 displacement due to its remarkable ability to modify the mobility ratio of the flood. However, the application of this technique strongly depends on the generation of high-quality foam in a target porous medium that may be undermined by gravity drainage under reservoir condition. By injecting foamed CO_2 stabilized by surfactants or nanoparticles, both of the aerial and vertical sweep efficiencies can be significantly improved regardless of CO_2 being in its gaseous or supercritical state (Ren et al., 2013). This benefit stems from the reduction of gas mobility by the presence of thin foam film, named lamellae. The foaming ability and foam stability are the two other essential variables to consider when designing and implementing a foam flooding process (Saputra et al., 2013). The creation and coalescence of lamellae have a considerable effect on the foaming ability in porous media while foam stability is generally determined by both the molecular structure of the foaming agents and the in-situ reservoir conditions. Studies conducted to date on the CO_2 foam floods have been focusing on several aspects of such foods including the synthesis and evaluation of suitable foaming agents and the applicability and efficiency of various foam injection schemes (Borchardt et al., 1985, Tortopidis, 1994, Bogdanovic et al., 2009, Kang et al., 2010).

Another technique with the potential to counteract the challenges encountered during continuous CO_2 flooding is the WAG (water-alternating-gas) flooding scheme. Caudle and Dyes (1958) developed the idea of injecting water in alternation with gas for the first time. The first reported WAG field test was performed by Mobil in 1957 in the North Pembina Field in Alberta, Canada (Van Poollen, 1980). Since then, around 60 field applications have been conducted worldwide (Figure 7). This injection scheme can reduce the viscous instabilities by suppressing the mobility of CO_2 during a CO_2-EOR process. In other words, this technique tends to combine the improved mobility ratio of water-flooding with the excellent microscopic sweep efficiency of CO_2 injection (Caudle and Dyes, 1958). Therefore, in a WAG process, controlling the amount of the injected gas and water is of key importance to achieve the best possible displacement performance. The injected water influences the vertical sweep efficiency while the injected gas plays a critical role in controlling the microscopic displacement efficiency (Birarda et al., 1990, Reinbold et al., 1992). The WAG processes may be broadly classified into the two groups of miscible and immiscible displacements with the majority of the projects worldwide are reported to be of miscible type (Graham et al., 1980, Brownlee and Sugg, 1987, Hsie and Moore, 1988, Prieditis et al., 1991). Christensen et al. (2001), who reviewed over 50 field projects, reported that in general WAG flooding results in 51.0% increase in the oil recovery. According to this review, about 88% of WAG projects were applied onshore with nearly 79% found to operate under miscible conditions and about 57% applied in sandstone reservoirs (Figure 7). Nearly all of these miscible WAG projects included the process of reservoir re-pressurization to reach miscible conditions. However, due to the extreme difficulties associated with maintaining a high enough pressure, at a typical real field case a mixed process of a miscible and immiscible WAG is often implemented. On the other hand, the immiscible WAG injection gained a wide application in reservoirs where gravity override was a major concern due to either the low dip or pronounced heterogeneity (Ma and Youngren, 1994, Robie et al., 1995, Grigg and Schechter, 1997). Several technical and economic factors may influence the outcome of a WAG flood including the slug size, injection order or the sequence of the slugs, number of slugs injected, density and viscosity contrast between CO_2 and water, etc. The cost and availability of CO_2 and the necessary injection infrastructure may also dictate the feasibility of the process.

One key application of a WAG flooding is to suppress the negative effects that formation heterogeneity may have on the performance of a CO_2-EOR flood by stabilising the displacement front. To date there have been many experimental studies conducted to evaluate and optimise the performance of the WAG injection scheme, however, almost all of such work has focused on homogenous porous media. To bridge this identified gap, a systematic approach has been taken in the current research to experimentally study the performance of WAG injection in heterogeneous layered porous systems. As highlighted in later chapters of this thesis, such data would be highly insightful in revealing the actual mechanisms through which WAG may help to achieve a better oil recovery profile with important implications for numerical modelling of such displacements.

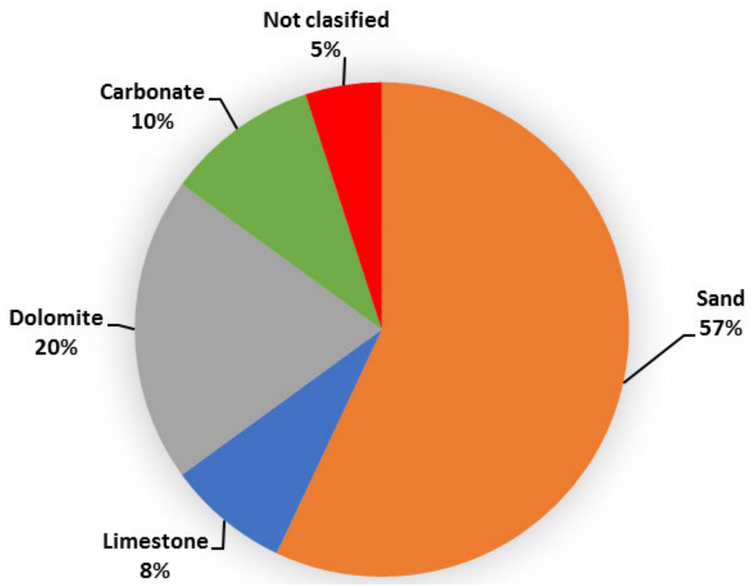

Figure 7. WAG field applications (Christensen et al., 2001).

2.3.3 Flooding Mode: Tertiary versus Secondary

According to a more conventional definition, EOR techniques would be classified as tertiary recovery type (conducted under the tertiary mode). As a result, the majority of research work completed to date have evaluated the efficiency and viability of such techniques based on the above definition. However, several studies have looked into the possibility of performing EOR methods right after the primary recovery stage (conducted under the secondary mode) (Wang, 1980, Mungan, 1981, Tiffin and Yellig, 1983, Shyeh-Yung, 1991, Srivastava et al., 1994, Kulkarni and Rao, 2005, Almehaideb et al., 2008, Jiang et al., 2012, Sohrabi et al., 2012, Fernø et al., 2015). As mentioned earlier, CO_2 flooding can be an ideal tertiary recovery technique for depleted oil reservoirs especially for those with depths greater than 800 meters (beyond this depth, CO_2 would take on its supercritical state (Saeedi, 2012)), oil gravity above 22 °API and residual oil saturations more than 25% (Prieditis et al., 1991, Ring and Smith, 1995). The above particular conditions would be desirable since such suitable in-situ conditions and oil composition would maximize the displacement efficiency of the CO_2 flood.

Despite the benefits of CO_2-EOR, its late application may suffer from reduced flood efficiency. For example, Riazi et al. (2009) experimentally observed the deteriorating CO_2 flooding performance after water injection at the pore scale. Similarly, Wylie and Mohanty (1997) experimentally showed that, at high water saturations, the intended interactions between the injected CO_2 and in-situ oil would be reduced due to the isolation of oil from CO_2 by water (i.e. water shielding). In other words, the high mobile water saturations after water-flooding leads to a reduction in gas/oil interfacial area hindering mass transfer between the two phases (Wylie and Mohanty, 1997). A number of researchers have also demonstrated and discussed that an incremental increase in water saturation due to a water flood can result in a significant water shielding effect in a subsequent solvent flooding in water-wet porous media (Raimondi and Torcaso, 1964, Brigham and Dew, 1968, Stalkup, 1970, Shelton and Schneider, 1975) but such an effect would be less severe or non-existent in the oil-wet media (Tiffin and Yellig, 1983, Spence and Ostrander, 1983, Ehrlich et al., 1984, Jackson et al., 1985, Huang and Holm, 1988). Due to the injection of water in alternation with gas, a WAG flood is also prone to water shielding or water blocking effect (Tiffin et al., 1991). In addition to the above-mentioned experimental observations, some researchers have attempted to quantify the adverse consequence of such effects theoretically (Grogan and Pinczewski, 1987, Do and Pinczewski, 1993, Bijeljic et al., 2002).

As revealed by the above review of the existing literature, although comparing the performance of CO_2-EOR under the secondary and tertiary modes may not be considered a new area of research, none of the published pieces of literature has so far experimentally evaluated the above in the presence of heterogeneity for either of the continuous CO_2 injection or WAG flooding scheme. Hence investigating the above has formed a major objective of the current work in which core-scale heterogeneity has been introduced into the CO_2-EOR experiments conducted using a systematic and reproducible approach.

2.3.4 Miscible versus Immiscible Flooding

In general, depending on the conditions, CO_2 flooding process can be classified as immiscible, near miscible or miscible (Holm, 1982). The minimum miscibility pressure (MMP) of the reservoir oil is a key parameter controlling the nature of displacement in terms of miscibility. The MMP is theoretically defined as the minimum pressure at which the injected CO_2 may develop in-situ dynamic miscibility with the oil at reservoir temperature (Stalkup, 1983). In other words, this is the pressure at which the interface between CO_2 and reservoir oil disappears due to extremely low or near zero IFT. Traditionally, slim-tube experiments are used to measure the MMP which is defined as the pressure where more than 90.0% of OOIP is recovered at 1.2 pore volumes of CO_2 injected (Figure 8) (Yellig and Metcalfe, 1980). Carbon dioxide is considered a favourable displacing agent in part because it induces a relatively low MMP with a wide range of crude oil types. Upon injection, CO_2 is capable of extracting lighter fractions (C_5-C_{30}) from the reservoir oil and developing miscibility after multiple contacts mobilising the trapped oil the microscopic level (Salem and Moawad, 2013). It can be used to recover light and medium-light oils (>30 API) in shallow reservoirs at low temperatures.

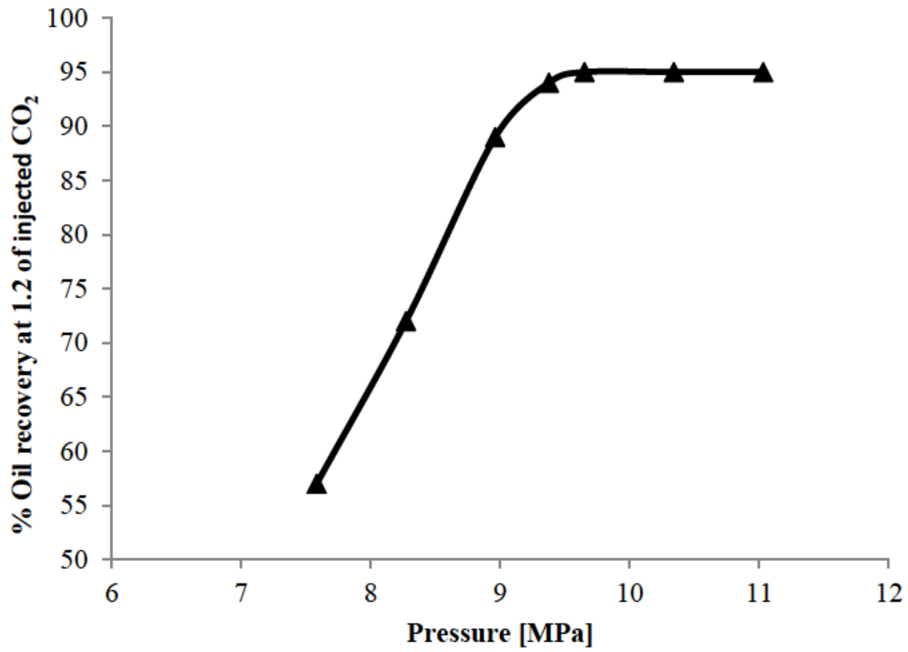

Figure 8. Measured MMP of oil using a slim-tube method (modified after (Yellig and Metcalfe, 1980)).

Miscible displacement takes place when the prevailing in-situ pressure of a CO_2 flood is above the MMP of the oil reservoir. Under miscible conditions, CO_2 is capable of lowering the crude oil viscosity dramatically as well as swelling the in-situ oil (Yongmao et al., 2004). In general, there are aspects of the miscible flood that limit its microscopic sweep efficiency and, as a result, the effective mechanisms and the performance of the flood would differ significantly. On the other hand, in immiscible flooding, capillary forces arise from the fact that there is a distinct interface between the fluid phases due to the appreciable IFT of the fluid system. The effect of capillary forces on an immiscible displacement can be characterized using the capillary number (N_C), which is defined as the ratio of viscous to capillary forces (Ayirala and Rao, 2004) as depicted by Eq. 2

$$N_c = \frac{v\,\mu}{\delta cos\theta} \qquad \text{Eq. 2}$$

where, v and μ are the velocity and viscosity of the displacing fluid, respectively, δ is the IFT of the fluid system and Θ is the contact angle that is used to determine wettability. Due to the appreciable IFT value, an immiscible flood would have a finite N_C value resulting in a considerable residual saturation for the displaced phase at the microscopic scale (i.e. low microscopic sweep efficiency) (Nobakht et al., 2007).

On the other hand, a miscible CO_2 flood, theoretically, can result in the recovery of nearly 100% of the OOIP under ideal conditions (e.g. $M \leq 1$, homogeneous formation, etc.). However, it has the potential to generate 10.0-20.0% incremental recovery after water flooding in field applications (Yongmao et al., 2004, Enick et al., 2012). The effectiveness of the miscible flooding to improve E_D is often a highly desirable outcome which is achieved through a number of mechanisms including oil swelling, IFT reduction to near-zero values (i.e. $N_c \approx \infty$) and decrease in the viscosity and density of the crude (Holm and Josendal, 1974, Nobakht et al., 2008, Ding et al., 2013). In a miscible flood, depending on how miscibility is achieved, CO_2 may be first contact miscible (FCM) or multiple contact miscible (MCM) with the reservoir oil. First contact miscibility occurs when the injected CO_2 and reservoir oil mix in any proportion when they first come in contact under reservoir conditions (Holm, 1986). An MCM flood, on the other hand, involves a gradual dynamic mixing of CO_2 and the reservoir oil as the flood proceeds. In general, three main mass transfer mechanisms are responsible for this mixing, namely, solubilisation, diffusion and dispersion (Sehbi et al., 2001). Among these three mechanisms, solubilisation has the most influence. During the MCM flood, CO_2 is first transferred into the crude oil causing it to swell which lowers its density and viscosity (Holm and Josendal, 1974, Nobakht et al., 2008, Ding et al., 2013). The lighter components of the oil also vaporize into the CO_2-rich phase making it denser and more viscous. Therefore, as the mass transfer continues, the difference between the properties of the CO_2/oil-rich phases diminishes (Stalkup, 1983, Green and Willhite, 1998, Jarrell et al., 2002). Despite its outstanding microscopic sweep efficiency, similar to immiscible flooding, the miscible flooding may still suffer from gravity override and viscous instability both of which can be further intensified by formation heterogeneity negatively impacting on the macroscopic sweep lowering its overall sweep efficiency (Eq. 1).

To date, there have been numerous experimental and numerical simulation studies focused on evaluating the performance of both miscible and immiscible CO_2-EOR. However, the published literature covering the experimental evaluation of the effect heterogeneity on both flood types are very limited. In the current research, the performance of both miscible and immiscible floods in heterogeneous porous media has been investigated at the laboratory scale using a carefully designed and systematic experimental procedure. As presented and discussed in the upcoming chapters, the outcomes of the research work have demonstrated the differences between the two flood types in terms of displacement efficiency and recovery profile which can be attributed to differing mechanisms active during the two floods.

2.3.5 Effect of Reservoir Heterogeneity

As mentioned earlier, while much research has been conducted in homogeneous systems, the literature on multiphase flow behaviour in heterogeneous media is sparse. In the upstream petroleum industry, the term heterogeneity is often used to describe a variation in permeability, porosity, thickness, rock facies or fluid saturation as well as the presence of faults and fractures within a reservoir (Chopra, 1988, Lake and Jensen, 1989). However, in general, most forms of heterogeneity, in one way or another, involve a variation in permeability. For both miscible and immiscible flooding, the efficiency of a CO_2-EOR process may be reduced by an unfavourable mobility ratio and viscosity/density contrast resulting in viscous fingering and/or gravity segregation. The negative impact of such effects would become further pronounced by the presence of reservoir heterogeneity (Grigg and Schechter, 1997) leading to even earlier CO_2 breakthrough. This leaves behind a large proportion of oil bypassed and residually trapped and result in a fast rise in the CO_2 to oil ratio in the production stream making the overall EOR process potentially uneconomical. In general, the reservoir heterogeneity can greatly change a field’s reservoir management strategy if found to be adversely affecting the hydrocarbon production.

Reservoir heterogeneity may occur at various scales from pore-scale (micrometres) to reservoir scale (kilometres). The reservoir scale or macroscopic heterogeneities, such as permeability zonation and bedding, can affect both vertical and horizontal sweep and commonly result in unswept or bypassed zones. Microscopic heterogeneity is the variability at the pore-scale and determines the level of residually trapped oil within the swept zones. Such residual oil is not usually moveable via secondary recovery techniques such as water flooding and therefore would require enhanced recovery techniques to be recovered. On the other hand, the bypassed oil associated with macroscopic heterogeneity is non-residual and hence technically movable at reservoir conditions. A major detrimental effect of macroscopic heterogeneity becomes evident by preventing the microscopic sweep efficiency of an EOR flood to be put into use across the bypassed zones that are not contacted by the displacing fluid.

In a heterogeneous reservoir, the vertical sweep efficiency is adversely affected if the flow is dominated by advection or channelling of the oil-displacing agent. In that case, the displacing agent would flow preferentially through the high permeability layer(s) and would leave the low permeability layer partially swept. On the other hand, flow dominated by dispersion would increase the vertical sweep efficiency. Shedid (2009) conducted a core flooding study to investigate the effect of three different types of heterogeneity on oil recovery during miscible CO_2 flooding. The first type of heterogeneity was represented by a single synthetic fracture in a core plug with different inclination angles. The second type was introduced as layered samples made up of three core slabs obtained by axially splitting intact plugs into three pieces with each slab having a different permeability. Finally, the third group of heterogeneous samples included composite cores made up of short core segments placed one after another in series (aligned in different permeability sequences) with each segment having a different permeability. Shedid (2009) concluded that heterogeneity can impact on the oil recovery profile considerably. In particular, he reported that for layered samples, the highest recovery was obtained from the medium-high-low permeability arrangement (from top) whereas the low-medium-high permeability sequence in the direction of the flood resulted in the highest recovery in the composite cores. In another study, Zhao et al. (2015) experimentally examined oil recovery during CO_2-EOR in layered samples. Their samples were prepared similar to those constructed by Shedid (2009) but had two layers only resulting in different permeability ratios (PR) between the half plugs included in a single-layered sample (i.e. 10, 30, 100, and 500). They observed that the pressure drop during CO_2 displacement would decrease dramatically with the increase in the PR and the remaining oil in low permeability layer could not be effectively displaced due to the high mobility of CO_2 through the high permeability one. Zhou et al. (2015) investigated the impact of both CO_2 gravity override and permeability ratio on oil recovery performance using a dual-core core flooding apparatus. Their results revealed the detrimental impact of permeability ratio on oil recovery and the poor sweep efficiency in the lower permeability zone caused by the bypassing of fluids through the higher permeability zone. Bikkina et al. (2016) conducted another laboratory investigation to evaluate the influence of wettability and permeability heterogeneity on the performance of miscible CO_2-EOR. Similar to other work reported above, the permeability heterogeneity was obtained by combining two half pieces of axially split water-wet core samples of different permeabilities with no crossflow. Their results showed an overall recovery factor of only 0.0-5.0% after injecting three pore volumes of CO_2. The low additional recovery reported by Bikkina et al. (2016) may be attributed to the channelling of CO_2 through the open space left in-between the adjacent half plugs as they used a very low net-effective stress applied to their samples during flooding. Ding et al. (2017) found the oil recovery to be very sensitive to heterogeneity in a two-layer system with a PR range of 1.0-154. Their findings showed that even a weak heterogeneity (i.e. low PR) could lead to a large decrease in the recovery of miscible flooding. They also found the oil recovery rate and the ultimate RF in homogeneous cores (PR = 1.0) to be higher than that of the heterogeneous ones (PR= 2.2, 15.5, and 154.0). For instance, recovery in a homogenous core was 95.0% compared with 58.3%, 50.0% and 39.8% for PR's of 2.2, 15.5, and 154.0, respectively. Bahralolom et al. (1988) observed that the existence of a preferential flow path in visual etched-glass models resulted in early breakthrough and increase in the CO_2 volume required to displace the oil. However, when 1.5 pore volume (PV) CO_2 was injected, approximately 100% of the oil was removed via a MCM CO_2 flood. Also, Al Wahaibi and Al Hadhrami (2011) observed early breakthrough and delayed recovery in heterogeneous bead-packed models with permeability in the range of 10-25 μm^2. However ultimately, the oil recovery in their models reached nearly 100% under FCM CO_2 injection. The effect of the presence of fractures was investigated in the laboratory by creating an artificial fracture in core plugs (Fjelde et al., 2008, Shedid, 2009). These researchers concluded that unfractured cores would yield a higher recovery compared with fractured ones during CO_2 injection. In another study, Fernø et al. (2015) found the oil recovery in synthetic fractured media to be dominated by fracture permeability and that the RF of miscible CO_2 injection in such media varied from 30.0% to 90.0%. Khosravi et al. (2014) also found the miscible CO_2 injection to be capable of achieving an RF above 80.0% in fractured media. Having one point in common, the studies referred to so far all agreed that heterogeneity would inevitably lead to an early breakthrough and reduced recovery as well as increase in the required amount of CO_2 to recover the in-situ oil. Pande and Orr (1994) presented the results of a study in which they used an analytical approach to calculate the recovery of CO_2 flooding in a two-layered system by changing the permeability ratio of the layers. Their results showed a dramatic decrease in recovery with increased heterogeneity depicted by an increase in permeability ratio in the range of 1.0-10.0. The results obtained by these researchers revealed a more pronounced influence of gas channelling on sweep efficiency than the crossflow. Several numerical simulation studies have also shown the importance of small (sub-core) scale heterogeneity on multiphase fluid displacement (Chaouche et al., 1993, Krause et al., 2011).

As revealed by the above literature review, there have been a few core-scale experimental studies conducted to date in which the effect of layered and composite heterogeneity on the performance of CO_2-EOR has been investigated systematically. However, as revealed by various sections included in this chapter so far, the current study has aimed to gain a deeper understanding of the displacement performance of CO_2-EOR in heterogeneous media using an integrated and objective experimental approach. This included systematically evaluating the effect of a number of important factors (either in isolation or when combined with other factors) including the CO_2 injection scheme (WAG versus continuous), miscibility condition, degree and arrangement of heterogeneity and the flooding mode (tertiary versus secondary). More importantly, the results of some major parts of the above investigation were qualitatively and quantitatively scrutinised with the aid of an X-ray Computed Tomography (XCT) scanner which helped to shed light on the way some critical phenomena such as interlayer crossflow may influence oil recovery profile. Such results may be considered significant in the way they improve the current understanding of multiphase flow in heterogeneous porous media during CO_2-EOR and how some of the contributing factors may positively or negatively influence the outcome of such an EOR technique.

2.3.6 Crossflow in Layered and Fractured Porous Media

The mass transfer phenomena, crossflow, between layers has been recognised as an important factor to consider when flooding layered porous media. The cross-flow may occur due to various pore and core-scale forces and mechanisms such as the viscous forces (Sorbie et al., 1990, Sorbie and Seright, 1992, Firoozabadi and Tan, 1994) which may be of high importance in a displacement under favourable mobility ratio. Other influential mechanisms include the diffusion and dispersion (Hara and Christman, 1993, Mohanty and Johnson, 1993) that may play a considerable role in influencing the displacement if the injected gas is fully or partially miscible with the oil. As the other two forces that may influence crossflow, the gravity and capillary forces may also be dominant during immiscible floods (Fayers and Lee, 1992, Burger and Mohanty, 1997).

A number of studies have focused on understanding the factors that influence hydrocarbon recovery in layered porous media with some unravelling and quantifying the influence of crossflow during this process. Cinar et al. (2004) and Alhamdan et al. (2012) found the fluid flow and recovery during floods conducted in a two-layer glass bead system under low IFT (i.e. minimal capillary effects) to be dominated by gravity and viscous forces. Other experimental (Cinar et al., 2004, Marcelle-De Silva and Dawe, 2009) and numerical simulation (Kortekaas, 1985, Debbabi et al., 2017b) studies have demonstrated the dominance of capillary forces in determining the flow patterns during immiscible displacement in layered systems. Burger et al. (1996) indicated that the phase behaviour of a fluid system plays a significant role in controlling the mass transfer from a bypassed region to a flowing region. Peters et al. (1998) performed miscible flooding experiments and revealed that greater gravitational effects would increase crossflow and improve recovery when gravity and viscous forces oppose each other under favourable flooding conditions, or they may act together under unfavourable flooding condition. Similarly, Zapata and Lake (1981) and Debbabi et al. (2017a) demonstrated that mobility contrast plays a significant role in improving vertical sweep efficiency in a stratified reservoir. Yokoyama and Lake (1981) suggested that transverse capillary pressure effects tend to increase oil recovery in stratified media when the transverse capillary number is about 0.1, while an increase in the capillary number to 10-100 would result in complete mixing (i.e. miscibility). Overall, given the influence of different factors on mass transfer between layers and based on the research results obtained to date, it could be concluded that crossflow may, to some extent, counteract the negative effects of layering and improve vertical sweep efficiency (Araktingi and Orr, 1990, Cinar et al., 2004, Al-Bayati et al., 2018b). This phenomenon would improve recovery by diverting oil from a low permeability layer into a higher permeability one (Dindoruk and Firoozabadi, 1997). Crossflow can also reduce channelling through the high permeability regions (Pande, 1992, Bertin et al., 1998) by promoting a more pronounced two-phase flow and subsequently reducing the mobility of the displacing phase in the high permeability region (Pande and Orr, 1994, Al-Bayati et al., 2018a).

An extensive review of the current literature as presented above indicates that to date the contribution of crossflow during CO_2-EOR in layered media has not been quantified using core-flooding experiments. More significantly, no studies have yet evaluated the effect of interlayer crossflow visually with the aid of such tools as an XCT scanner.

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Chapter 3

3.1 Influence of permeability heterogeneity on miscible CO_2 flooding efficiency in sandstone reservoirs- An experimental investigation

AL-BAYATI, D., SAEEDI, A., XIE, Q., MYERS, M. B. & WHITE, C. 2018. Influence of Permeability Heterogeneity on Miscible CO_2 Flooding Efficiency in Sandstone Reservoirs: An Experimental Investigation. *Transport in Porous Media,* 125**,** PP 341-356.

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Influence of Permeability Heterogeneity on Miscible CO_2 Flooding Efficiency in Sandstone Reservoirs: An Experimental Investigation

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Abstract

In this study, we systematically investigate the effect of core-scale heterogeneity on the performance of miscible CO_2 flooding under various injection modes (secondary and tertiary). Manufactured heterogeneous core plugs are used to simulate vertical and horizontal heterogeneity that may be present in a reservoir. A sample with vertical heterogeneity (i.e. a layered sample) is constructed using two axially cut half plugs each with a distinctly different permeability value. In these samples, the permeability ratio (PR) defines the ratio between the permeabilities of adjacent half plugs. Horizontal heterogeneity (i.e. a composite sample) is introduced by stacking two or three short cylindrical core segments each with a different permeability value. Our special sample construction techniques have also enabled us to investigate the effect of permeability ratio and crossflow in layered samples and axial arrangement of core segments in composite samples on the ultimate recovery of the floods. Core flooding experiments are conducted with an *n*-Decane–brine–CO_2 system at a pore pressure of 17.2 MPa and a temperature of 343 K. At this temperature, the minimum miscibility pressure of CO_2 with *n*-Decane is 12.6–12.7 MPa so it is expected that at 17.2 MPa CO_2 is fully miscible with *n*-Decane. The results obtained for both the composite and layered samples indicate that CO_2 injection would achieve the highest recovery factor (RF) when performed under the secondary mode (e.g. layered: 79.00%, composite: 89.83%) compared with the tertiary mode (e.g. layered: 73.2%, composite: 86.2%). This may be attributed to the effect of water shielding which impedes the access of the injected CO_2 to the residual oil under the tertiary injection mode. It is also found that the oil recovery from a layered sample decreases noticeably with an increase in the PR as higher PR makes the displacement more uneven due to CO_2 channelling. The RFs of 93.4, 87.89, 77.9 and 69.8% correspond to PRs of 1, 2.5, 5, and 12.5, respectively. In addition, for the layered samples, crossflow was found to have an important role during the recovery process; however, due to excessive channelling, this effect tends to diminish as PR increases. Compared with the layered heterogeneity, the effect of composite heterogeneity on the RF seems to be very subtle as the RF is found to be almost independent from the permeability sequence along the length of a composite sample. This

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outcome may have been caused by the small diameter of the plugs resulting in invariable 1-D floods.

Keywords Heterogeneous porous media · CO_2 flooding · Miscible flooding · Enhanced oil recovery · Crossflow · Multiphase flow

1 Introduction and Background

Laboratory research work and field operations have shown that after the completion of the primary and secondary recovery stages that as a global average nearly 60% of the original oil in place remains trapped underground (Donaldson et al. 1985; Tunio et al. 2011). Furthermore, given the decline in the number of new discoveries over the recent decades, much of the world's oil production comes from mature oil fields (Alvarado and Manrique 2010). As a result, there is a real possibility of steep decline in the global oil production in the near future unless suitable and cost-effective enhanced oil recovery techniques can be employed to help unlock at least some of the trapped oil. It is estimated that EOR has the potential to increase the average oil recovery factor (RF) to around 65% (Tunio et al. 2011; Lake 1989).

Carbon dioxide injection is proven to be an effective enhanced oil recovery technique. CO_2 flooding as an EOR method (CO_2-EOR) dates back to the early 1950s (Whorton and Kieschnick 1950; Whorton et al. 1952; Holm 1959). In more recent years, CO_2-EOR has captured more interest as its potential to also reduce CO_2 emissions and combat global warming has been considered. Some other advantages include very high potential RF, availability of CO_2 in many parts of the world (e.g. presence of natural CO_2 reservoirs or pre-existing CO_2 pipelines) and the ease of achieving miscibility when compared with other gases (Cooney et al. 2015; Kamali et al. 2016; Saeedi 2012; Trivedi and Babadali 2006; Zhao et al. 2014; He et al. 2016). The performance of a CO_2 flooding process is controlled by a number of operational factors and reservoir properties including the reservoir pressure and temperature, in situ phase behaviour of the fluid system, capillary pressure, wettability, compositional effects, interfacial tension (IFT), reservoir geology and formation heterogeneity. The potential effects of some of these factors have already been investigated by a number of research groups (Al Sulaiman et al. 2016; Bikkina et al. 2016; Jiménez-Martínez et al. 2016; Li et al. 2015; Pini et al. 2012, 2013; Yongmao et al. 2004).

In general, depending on the conditions, a CO_2 flooding process can be classified as immiscible, near miscible or miscible. A miscible CO_2 flood can result in an RF close to 100% by improving microscopic sweep efficiency which is achieved through oil swelling and reduced oil viscosity and density (Ding et al. 2013; Nobakht et al. 2008; Holm and Josendal 1974). Another important mechanism is the significant reduction in the interfacial tension (IFT) of the fluid system. Under miscible conditions, when CO_2 comes into contact with the oil in the reservoir, they would begin mixing together leading to the disappearance of capillary forces and the eventual formation of a single-phase fluid (Stalkup 1983; Jarrell et al. 2002). However, despite its excellent microscopic sweep efficiency, similar to immiscible flooding, the miscible flooding suffers greatly from formation heterogeneity which negatively impacts on the macroscopic sweep lowering the overall sweep efficiency. In fact, when it comes to core flood experiments, one of the critical factors that may make the field-scale results to differ from those achieved from the laboratory experiments is the effect of heterogeneity which is normally highly pronounced at the field-scale but is often deliberately excluded from the laboratory experiments that follow a standard flooding procedure. Therefore, while the miscible CO_2 flooding can lead to the recovery of nearly 100% of the original oil in place (OOIP) under homogeneous conditions, it has the potential to generate 10–20% incremental recovery after water flooding in field applications (Yongmao et al. 2004; Enick et al. 2012).

In the petroleum industry, heterogeneity within a reservoir is the variation of permeability, porosity, thickness, rock facies and fluid saturations or the presence of faults and fractures (Lake and Jensen 1989; Chopra 1988). However, most forms of heterogeneity, in one way or another, involve a variation in permeability. For both miscible and immiscible flooding, the efficiency of a CO_2-EOR process may be reduced by an unfavourable mobility ratio and viscosity contrast resulting in viscous fingering and/or gravity override. Such effects would become highly pronounced by the presence of reservoir heterogeneity (Grigg and Schechter 1997) leading to early CO_2 breakthrough. This leaves most of the residual/trapped oil and results in a fast rise in the CO_2 ratio in the production stream potentially making the overall EOR project uneconomical. Shedid (2009) conducted a core flooding study to investigate the effect of different reservoir heterogeneities on oil recovery during miscible CO_2 flooding. The heterogeneities were represented by a single synthetic fracture with different inclination angles, layered samples made up of core slabs obtained by axially splitting intact plugs into three pieces with each slab having a different permeability and, finally, composite cores made up of short core segments placed one after another in series (aligned in different permeability sequences) with each segment having a different permeability. Shedid (2009) concluded that for layered reservoirs, the highest recovery was obtained from medium–high–low permeability arrangement (from top), whereas low–medium–high permeability sequence resulted in the highest recovery in the composite reservoir. Zhao et al. (2015) experimentally examined oil recovery in layered samples. Their samples were prepared similar to those constructed by Shedid (Shedid 2009) but had two layers only resulting in different permeability ratios (PR) between the half plugs included in a single layered sample (i.e. 10, 30, 100, and 500). They observed that the pressure drop during CO_2 displacement would decrease dramatically with an increase in the PR and the remaining oil in low permeability layer could not be effectively displaced due to the high mobility of CO_2 which would be magnified by the effect of heterogeneity. Zhou et al. (2015) investigated the impact of both CO_2 gravity override and permeability ratio on oil recovery performance using a dual-core core flooding apparatus. Their results revealed the detrimental impact of permeability ratio on oil recovery and the poor sweep efficiency in the lower permeability zone caused by the bypassing of fluids through the higher permeability zone. Bikkina et al. (2016) conducted another laboratory investigation to evaluate the influence of wettability and permeability heterogeneity on performance of miscible CO_2-EOR. Similar to other work reported above, the permeability heterogeneity was obtained by combining two half pieces of axially split water-wet core samples of different permeabilities with no crossflow. Their results showed a recovery of only 0–5% after injecting three pore volumes of CO_2. The low additional recovery reported by Bikkina et al. (2016) may be attributed to the channelling of CO_2 through the open space left in between the adjacent half plugs as they used a very low net-effective stress applied to their samples during flooding. Ding et al. (2017) found the oil recovery to be very sensitive to heterogeneity in a two layer system with a permeability ratio (PR) range of 1.0–154. Their findings showed that even a weak heterogeneity can lead to a large decrease in the recovery of miscible flooding. They also found the oil recovery rate and the ultimate RF in homogeneous cores ($PR = 1.0$) to be higher than that of the heterogeneous ones ($PR = 2.2$, 15.5, and 154.0). For instance, recovery in a homogenous core was 95.0% compared with 58.3, 50.0 and 39.8% for PR's of 2.2, 15.5, and 154.0, respectively. Bahralolom et al. (1988) observed that the existence of a preferential flow path in visual etched-glass models resulted in early breakthrough and increase in the CO_2 volume required to displace the oil. However, when 1.5 pore volume (PV)

CO_2 was injected, approximately 100% of the oil was removed via a MCM CO_2 flood. Also, Al Wahaibi and Al Hadhrami (2011) observed early breakthrough and delayed recovery in heterogeneous bead-packed models with permeability in the range of 10–25 μm^2. However ultimately, the oil recovery in their models reached nearly 100% under FCM CO_2 injection. In another study, Fernø et al. (2015) found the oil recovery in synthetic fractured media to be dominated by fracture permeability and that the RF of miscible CO_2 injection in such media varied from 30 to 90%. Khosravi et al. (2014) also found the miscible CO_2 injection to be capable of achieving a RF above 80% in fractured media. Having one point in common, the studies referred to so far all agreed that heterogeneity would inevitably lead to early breakthrough as well as increase in the required amount of CO_2 to recover the in situ oil. Pande and Orr (1994) presented the results of a study in which they used an analytical approach to calculate recovery of CO_2 flooding in a two layered system by changing the permeability ratio of the layers. Their results showed a dramatic decrease in recovery with increased heterogeneity depicted by increase in permeability ratio in the range of 1.0–10.0. The results obtained by these researchers revealed a more pronounced influence of gas channelling on sweep efficiency than the crossflow. In Table 1, we have compared the critical features of our experimental design with some of the above studies those specific to our work. Several numerical simulation studies have also shown the importance of small (sub-core) scale heterogeneity on multiphase fluid displacement (Chaouche et al. 1993; Krause et al. 2011).

In an attempt to bridge the existing gap in our knowledge, this study utilises a systematic experimental approach to investigate the effect of core-scale heterogeneity on the performance of miscible CO_2 flooding. The experiments are designed in a way so the effect of recovery modes (secondary and tertiary), heterogeneity direction (vertical and horizontal), degree of permeability heterogeneity (PR), occurrence or lack of crossflow, etc. can be evaluated.

2 Experimental Methodology

2.1 Equipment, Chemicals and Test Conditions

This study utilised a purpose built high pressure–high temperature core flooding setup. As can be seen in Fig. 1, the major components of the setup included a hydrostatic biaxial core-holder (Core Laboratories, FCH Series), three syringe pumps (Teledyne Isco, Model 65D) used for controlling the confining pressure and fluid injections and two stainless steel transfer cylinders used for storing and injecting *n*-Decane and CO_2. The synthetic formation brine was injected directly using one of the syringe pumps. Two absolute pressure transducers (Omega Engineering, PX309-2KG5V) were also used to record the inlet and outlet pressures of the core-holder. To provide a stable pressure regulation during the flooding process, a high-precision dome-loaded backpressure regulator (BPR) (Equillibar, U10L Series Precision BPR) was used in combination with a syringe pump as the source of applied set pressure.

A synthetic formation brine was prepared by dissolving analytical grade salts (Sigma-Aldrich) in 1 L of distilled water which included 20 g NaCl, 7 g KCl and 5 g $CaCl_2{\cdot}2H_2O$. The other two injection fluids were *n*-Decane (99 mol%, Sigma-Aldrich) and high-purity CO_2 (99.9 wt%, BOC Gases). The experiments were conducted at the temperature, pore pressure and confining pressure of 343 K, 17.23 and 34.46 MPa, respectively. The pore pressure was above the MMP of CO_2 into *n*-Decane at 343 K (i.e. 12.6–12.7 MPa) as reported in the literature (Georgiadis et al. 2010; Shaver et al. 2001). Therefore, during our flooding experiments, CO_2 would be first contact miscible with *n*-Decane.

Table 1 Comparison between the critical features of this study and those of previous similar work

Author	Lithology	Heterogeneity mode	PR	Fluid system	Condition	Comparison with our work
Shedid (2009)	Carbonate	Layered, composite	Not specified	Crude oil + miscible CO_2	27.57 MPa 394.26 K	No reference to the effect of permeability ratio, crossflow or recovery mode Used carbonate samples No evidence of establishing capillary continuity between layers (e.g. use of paper tissue) No reference to the confining pressure applied
Zhao et al. (2015)	Not specified	Layered only	1, 10, 30, 100, 500	Crude oil + immiscible CO_2	13.3 MPa 332.64 K	No evidence of establishing capillary continuity between layers (e.g. use of paper tissue) Low confining stress was used resulting in bypass
Zhou et al. (2015)	Carbonate	Dual-core system	35	Crude oil + miscible CO_2	22 MPa 375.15 K	Separate whole plugs with no direct communication to allow for crossflow Investigated one PR only Did not investigate the effect of recovery mode
Bikkina et al. (2016)	Sandstone	Layered only	Not specified	*n*-Hexadecane + miscible CO_2	9.65 MPa 297.15 K	PR is not specified No reference to the effect of PR, crossflow or recovery mode Did not use tissues to establish capillary continuity Low confining stress resulted in fluid bypass through the joint between half plugs
Ding et al. (2017)	Epoxy cemented artificial rock	Layered only	1, 2.2, 15.5, 154	Crude oil + immiscible CO_2 Crude oil + Miscible CO_2	15 MPa 381.15 K 30 MPa 381.15 K	No evidence of establishing capillary continuity between layers (e.g. use of paper tissue) Low confining stress was used

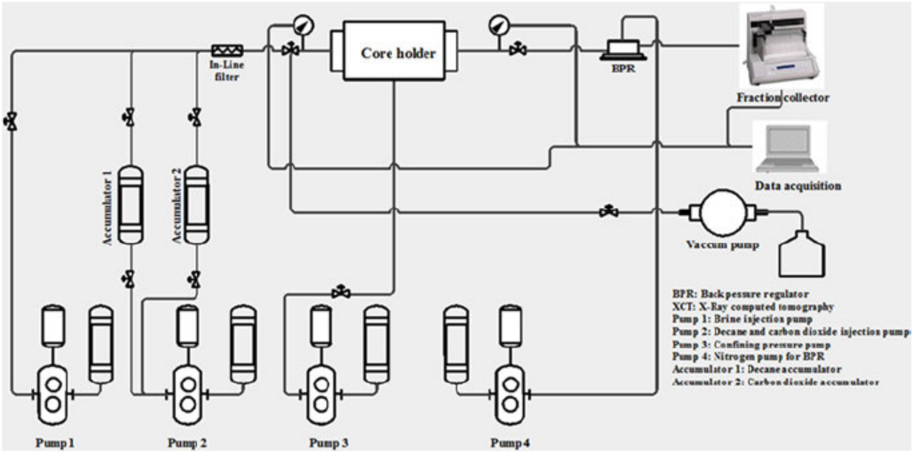

Fig. 1 Schematic diagram of the experimental setup used for the flooding tests

Table 2 Petrophysical properties of initial homogenous rock samples

Batch no.	Lithology	Nominal porosity (%)	Nominal permeability (mD)	Nominal length (mm)	Nominal diameter (mm)
1	Grey Berea sandstone	18	100	76.5	38.1
2	Bandera sandstone	19	20	76.5	38.1
3	Kirby sandstone	23	8	76.5	38.1

2.2 Core Samples

Initially, three batches of homogeneous core plugs (each batch had a known and significantly different permeability value) were sourced from quarried sandstone blocks in the U.S. The general characteristics of these samples are presented in Table 2. Subsequently, manufactured samples with axial and radial heterogeneity arrangements were assembled using the following procedures.

Radial heterogeneity (i.e. layered sample) was achieved by cutting homogeneous core plugs of different permeabilities axially into two halves and then constructing a heterogeneous plug by placing two halves each with a different permeability in parallel to make up a full diameter heterogeneous plug (Fig. 2a). Using this approach, three levels of heterogeneity were achieved by changing the permeability ratio (PR) between the two halves (Table 3). Furthermore, the effect of crossflow between the two half cores on the experimental results was evaluated by placing either an impermeable thin (1 mm) Teflon sheet or permeable lint-free tissue paper in between the two halves of the layered sample assemblies (Fig. 2b, c). In addition to polishing the cut surfaces of the half cores to a very smooth finish, the lint-free tissue paper also helped with establishing capillary continuity and promoting crossflow. Axially heterogeneous or composite samples were constructed by cutting homogeneous samples into approximately 35-mm-long segments and then stacking segments of different permeability

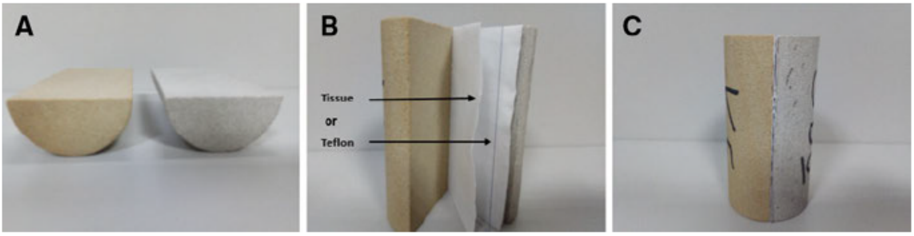

Fig. 2 Sample images of the layered cores

Table 3 Configuration of the layered samples constructed

Heterogeneity level	Batch no. of half plugs	Nominal permeability of half plugs (mD)	PR
Weak	2	20	2.5
	3	8	
Moderate	1	100	5
	2	20	
Strong	1	100	12.5
	3	8	

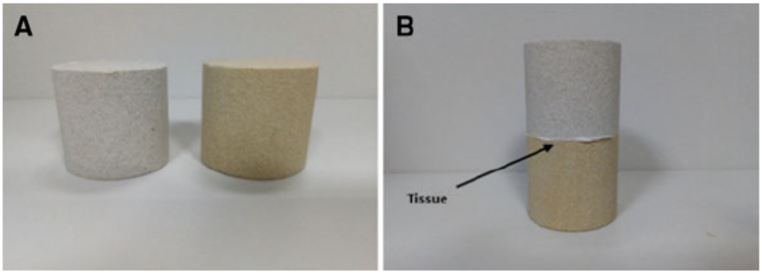

Fig. 3 Sample images of the composite cores

values in series one after another (Fig. 3). The lint-free tissue paper was again inserted into the polished joints of the core segments of the composite core to aid in establishing capillary continuity between the segments. It is worth noting that the 17.23 MPa net-effective stress (confining pressure minus pore pressure) applied to the samples was expected to help achieve a very close match between the layers or segments of the heterogamous samples.

2.3 Experimental Procedure

The core plugs were cleaned in a temperature controlled Dean–Stark apparatus using warm methanol and toluene and then dried in a vented oven at 343 K for 24 h or until their weights stabilised. Then, their porosity and permeability were measured using an automated helium porosi-permeameter before undergoing the flooding procedure. The core flooding procedure used here is designed based on the procedures and protocols available in the published literature (Saeedi 2012; Saeedi et al. 2011). To begin a core flood test, either an intact homogenous core or a heterogeneous core assembly (layered or composite) was wrapped with a multilayered sleeve to protect the core sleeve from damage during the core flooding process (Saeedi 2012). After loading, the wrapped sample into the core-holder, a low confining pressure (5 MPa) was applied to the sample and the sample was put under vacuum for 12 h. Formation brine was then injected into the sample to increase the pore pressure, while the confining pressure was also raised in the same way and the temperature was increased to the predefined value. The system was left under test conditions for 6 h to develop pressure and temperature stability throughout the system and to also achieve full brine saturation and establish adsorption equilibrium in the brine saturated sample. The brine permeability of the sample was then measured.

Approximately, five pore volumes (PV) of *n*-Decane were injected through the sample at 5 mL/min [i.e. a capillary number of $\approx 10^{-4}$] to achieve residual water saturation (S_{wr}). In the next step, depending on the EOR mode (secondary or tertiary) investigated, either CO_2 or brine was injected through the core sample. For EOR under tertiary mode, 4–6 PVs of brine were injected at 4 mL/min [i.e. a capillary number of $\approx 10^{-7}$] through the plug to establish residual *n*-Decane saturation. In the case of a secondary mode EOR, the previous step was skipped. Subsequently, CO_2 was injected at a flow rate of 0.5 cc/min. Throughout this procedure, the volume of *n*-Decane collected at the production side of the setup for each PV of injected CO_2 was recorded. The flooding was continued until 2–2.5 PVs of CO_2 were injected. The constant CO_2 injection rate of 0.5 mL/min was chosen as it agrees with the following equation proposed by Rapoport and Leas (1953):

$$L\mu V \geq 1 - 5 \tag{1}$$

where L is the length (m), V is the superficial velocity (m/s), and μ is the viscosity of the displacing fluid.

While following the above outlined procedure, we were initially concerned about the effectiveness of Decane injection in displacing the brine from the low permeability layer in the layered samples after the initial brine saturation stage. That is because during the injection, Decane may tend to flow through the high permeability layer bypassing the low permeability one. Such an effect would become more pronounced in the layered samples as the PR increases. To address this concern, we used an X-ray CT (X-ray computed tomography) imaging technique to verify fluid distributions at the conclusion of a Decane injection stage conduced on a sample with the highest PR examined in this work (PR = 12.5). The three images generated using this technique for three locations along the length of the sample are presented in Fig. 4. In this figure, the low permeability layer makes up the bottom half and the high permeability one the top half of every image. As evident from the images, Decane had indeed effectively flooded the low permeability layer. It is worth noting that to achieve this desirable outcome, we chose a relatively high flowrate (5 mL/min) to induce adequate differential pressure across the samples. Also, we injected an adequate volume (5 pore volumes) of Decane so it would displace the low permeability layer to residual brine saturation.

3 Results and Discussion

3.1 Influence of Layered Heterogeneity

We performed four core flooding experiments on layered samples (with crossflow; tissue paper was placed between half plugs) with different heterogeneity levels (i.e. different PR's).

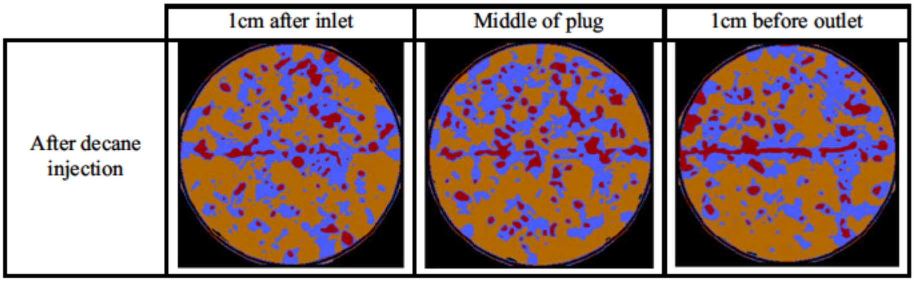

Fig. 4 X-ray images showing fluid distribution in a layered sample (PR = 12.5) at the end of the Decane injection stage. The light brown represents the rock matrix, blue coloured areas represent brine and red coloured spots show the pore space saturated with Decane

The PR values examined included 1.0, 2.5, 5 and 12.5 with a value of 1.0 indicating a homogeneous sample and values of 2.5, 5 and 12.5 representing weak, moderate and strong heterogeneity levels, respectively. Except for the changes in PR and the geometry of the heterogeneity, from one experiment to another all experimental parameters remained unchanged. In all four tests, CO_2 was injected under the secondary EOR mode. We have also done a comparison study between the performance of CO_2 flood under secondary and tertiary modes whose results are presented and discussed in a later section of this manuscript.

Figure 5 shows the Decane recovery versus number of PVs of CO_2 injected for the above-mentioned experiments, each curve representing a particular PR value. As expected, the ultimate recovery from the homogeneous core (PR = 1.0) is the highest (93.4%) and the duration of high recovery rate is the longest. The main reason for this observation is that the CO_2 front moves more evenly in this sample, and fluid distributions in the flooded part of the sample are expected to remain spatially more homogeneous even after breakthrough resulting in a more sustained higher recovery rate. For the other three heterogeneous samples, the recovery profile before breakthrough is similar to that of the homogeneous sample, but after breakthrough they tend to flatten out earlier resulting in lower eventual recoveries. In fact, the larger the PR, the lower the ultimate recovery and this is consistent with the results reported previously by other researchers (Zhao et al. 2015; Ding et al. 2017; Pande and Orr 1994; Al-Bayati et al. 2018). In the heterogeneous samples, the injected gas tends to channel through and follow the easiest path (i.e. the high permeability layer). Honouring the general material balance between the injection and production sides of the sample, such a behaviour would not impact on the recovery rate before breakthrough considerably, however after breakthrough, the channelling of CO_2 through the higher permeability layer limits the portion of the sample that can be contacted by CO_2 leaving a considerable amount of Decane behind in the lower permeability zone. Despite CO_2 channelling, the actual volume of Decane recovered in every case is sufficiently high that some of the recovered Decane originates from the low permeability layer. In addition to partial flooding by CO_2, other mechanisms such as extraction of oil via crossflow are expected to have helped with recovering Decane from the low permeability layer. The effect of crossflow on recovery will be covered in more details in an upcoming section of the manuscript.

It can also be seen from (Fig. 5) that the doubling of PR from 2.5 to 5 results in about 10% decrease in the ultimate recovery but increase in PR from 5 to 12.5 (a further 2.5 times increase) causes only 8% decrease in the recovery. This demonstrates that with an increase in PR, the effect of heterogeneity on recovery tends to diminish. The primary cause of such an observation is the diminishing contribution of the low permeability layer to the total recovery

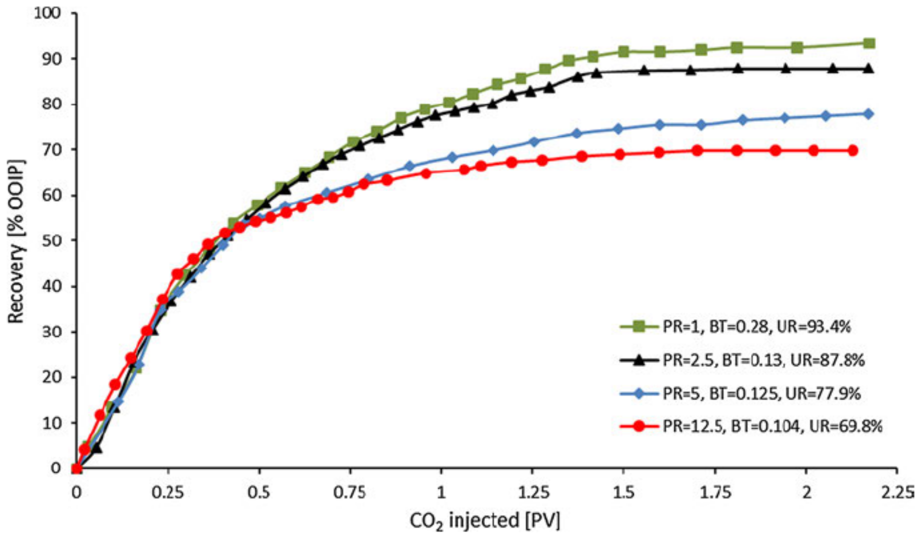

Fig. 5 Effect of permeability heterogeneity on oil recovery (*BT* breakthrough, *UR* ultimate recovery)

which approaches the recovery figure achievable if only the high permeability layer would be flooded alone. Pande and Orr (1994) have observed a similar trend among the RFs by varying PR in the range of 1.0–10.0. Zhao et al. (2015) have also reported a mere 9% decrease in the ultimate recovery by increasing the PR from 10 to 100. Burger and Mohanty (1997) attributed the low recovery of oil from the low permeability section to the capillary forces which diminishing mass transfer from low permeability to the high permeability zone.

3.2 Influence of Crossflow on Recovery

For the layered system, crossflow is one of the mechanisms for recovery enhancement during an EOR process. Viscous, capillary and gravity forces along with dispersion are four factors that influence degree of crossflow (Pande and Orr 1994; Dindoruk and Firoozabadi 1997; Fayers and Lee 1992; Zapata and Lake 1981). The occurrence of crossflow improves recovery by moving oil from a low permeability layer into the high permeability one as well as reducing the CO_2 mobility in the high permeability region by promoting two phase flow (Pande and Orr 1994; Al-Bayati et al. 2018). In this study, we performed six experiments with the objective of achieving a better understanding of the effect of crossflow on recovery under a range of different PR values. In the first set of three experiments, a lint-free tissue paper was inserted between the two halves of layered samples to promote crossflow. For the second set, samples similar to the first set were used (to give the same PR's) were used; however, for this set a thin (1 mm) Teflon sheet was inserted between the two halves preventing crossflow.

Figure 6 compares the ultimate recoveries achieved for every PR with and without crossflow. As expected, for both scenarios, the recovery decreases dramatically with an increase in PR. Comparing experiments with and without crossflow, it appears that crossflow works against the negative effects of gas channelling in layered systems resulting in a higher oil recovery across all PR values (Pande and Orr 1994; Al-Bayati et al. 2018; Fayers and Lee 1992; Zapata and Lake 1981). This effect was more pronounced for the weak and moderate heterogeneity levels (i.e. PRs of 2.5 and 5, respectively) and less evident for the highest PR

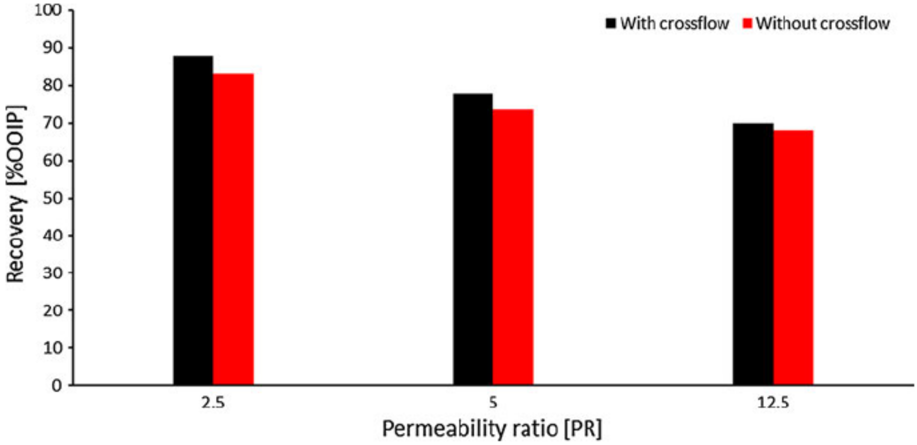

Fig. 6 Effect of crossflow on oil recovery

value (i.e. 12.5). This suggests that the effect of crossflow seems to have been neutralised by considerable channelling of the injected CO_2 through the high permeability layer reducing the amount of additional oil mobilised by crossflow. Using an analytical approach, Pande and Orr (1994) concluded that in layered systems, gas channelling has a more pronounced influence on sweep efficiency than crossflow.

3.3 Influence of EOR Mode (Secondary Versus Tertiary)

We also evaluated the effect of CO_2 injection mode (secondary and tertiary) on recovery for all heterogeneity schemes investigated (homogeneous, layered: PR = 5: with crossflow, and composite: Low–high; 8–100 mD). As can be seen in Fig. 7, across all cases tested, secondary mode (i.e. CO_2 injection without prior water flooding) results in higher recovery compared with the tertiary mode (i.e. CO_2 injection after the secondary water flooding). Similar results have been reported in the literature for homogeneous systems. In the experimental study conducted by Kulkarni and Rao (2005), secondary mode miscible floods resulted in higher oil recoveries than tertiary floods. Similarly, Zekri et al. (2013) concluded that the application of CO_2 flooding at early stage of oil recovery under the secondary mode results in higher oil recovery than its application under the tertiary mode. This is attributed to the presence of more mobile water phase for the late injection of CO_2 resulting in less oil production. Almehaideb et al. (2008) have also shown that an earlier miscible CO_2 injection during the recovery results in a higher ultimate oil recovery. Higher recovery resulting from the secondary recovery mode can be attributed to the less pronounced effect of water shielding which impedes the access of the injected CO_2 to the residual oil in the case of tertiary recovery mode (Saeedi 2012; Zekri et al. 2013; Tiffin and Yellig 1983; Ghedan 2009; Sohrabi et al. 2009). In other words, when CO_2 is injected under the secondary mode, the contact and miscibility between the oil and the injected CO_2 is facilitated.

Another observation from Fig. 7 is that under both secondary and tertiary modes, as may be expected, the highest recoveries were achieved for the homogeneous sample. Also among the two types of heterogeneous samples examined, the composite sample yielded higher recoveries. Such a difference can be attributed to the effect of fluid channelling and the bypass of Decane in the low permeability layer of the layered sample, something which

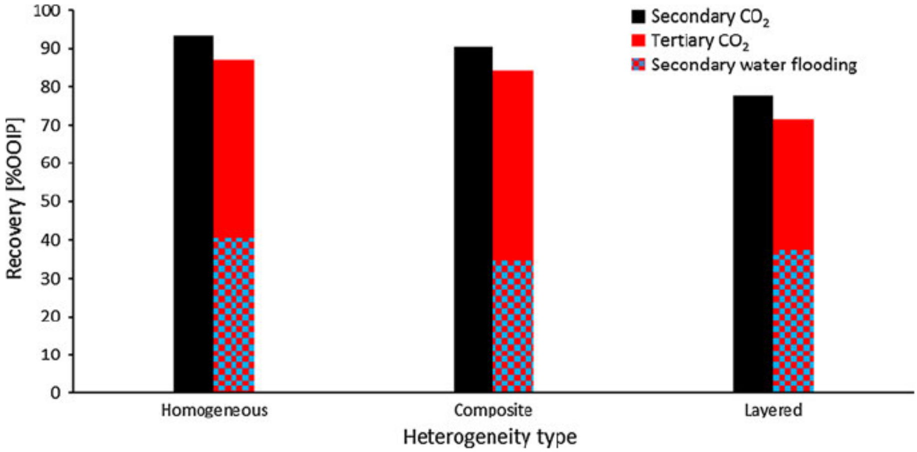

Fig. 7 Effect of recovery mode on ultimate oil recovery

does not take place in the composite sample. Although, as evident from Fig. 7, the amount of additional Decane recovered by the secondary CO_2 flood seems to remain consistent across all three sample types tested.

3.4 Influence of Composite Heterogeneity

Given the often natural horizontal layering of geological formations, the results obtained in this study for the layered samples may be considered of more relevance to real-life subsurface processes. However, the composite arrangement, although not very common, may exist in some reservoirs depending on the depositional environment in which the constituent rock formations were formed. As an another side to this study, as widely known, composite samples are often used in core flooding experiments to construct longer samples using which some of the experimental artefacts (e.g. capillary end-effect) would become less pronounced. Therefore, the results obtained here using the composite system can provide further insights about arranging the sample assemblies in such experiments.

Langaas et al. (1998) suggests that for a composite sample individual plugs need to be arranged with decreasing permeability in the flow direction to promote a more uniform displacement and achieve low residual saturation. However, the results of this work are more applicable to immiscible displacement where capillary forces are appreciable. Shedid (2009) experimentally evaluated the effect of permeability sequence in composite cores made up of three plugs with low (L), medium (M) and high (H) permeabilities on the ultimate recovery during miscible CO_2 flooding. In his study, the permeability sequences of medium–low–high (MLH) and medium–high–low (MHL) along the flow direction yielded recoveries of 91 and 81.5%, respectively, which were the highest among all the sequences examined.

We performed four experiments investigating the effect of permeability sequence in the direction of flow on the ultimate recovery of miscible CO_2 flooding. Our composite samples included either two or three individual plugs with low (L) or high (H) permeability values (i.e. 8 mD from batch 3, 100 mD from batch 1, respectively). Figure 8 presents the oil recovery versus PVs of CO_2 injected for the different permeability sequences of high-low (H–L), low–high (L–H), high–low–high (H–L–H), and low–high–low (L–H–L) along the length of

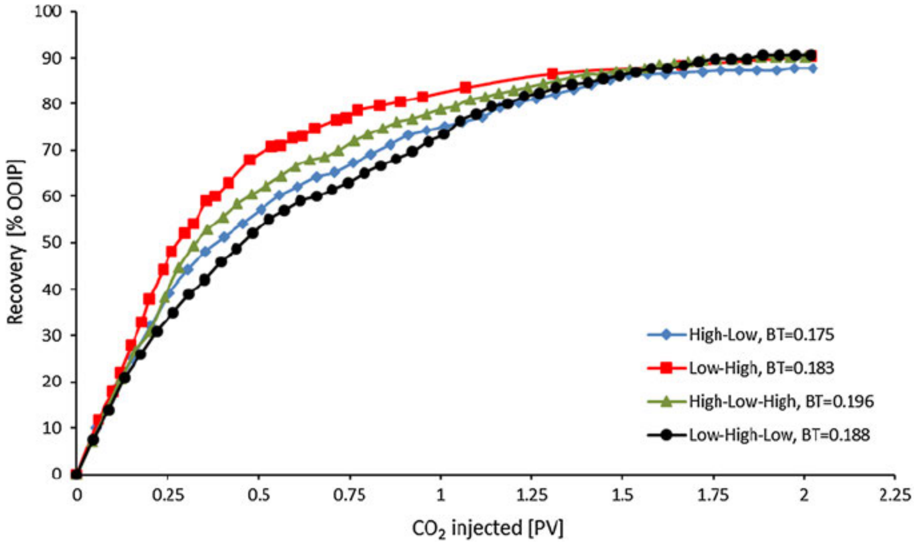

Fig. 8 Effect of horizontal heterogeneity on oil recovery (*BT* breakthrough)

the composite samples. As revealed by the figure, during intermediate injection times (i.e. 0.2–0.8 PVs), the composite cores with the high permeability plug placed at the outlet yielded better recovery. For example, oil recovery for the cases of H–L, L–H–L, L–H, and H–L–H at 0.8 PV injected is 69, 65, 78, and 73%, respectively. This behaviour may be attributed to the fact that in samples with low permeability plug placed at the inlet a larger differential pressure is imposed by this plug and initially the injected CO_2 becomes more compressed as it begins to penetrate the sample. However, once CO_2 passes through the low permeability plug and reaches the high permeability one, it becomes decompressed displacing Decane out of the sample with a higher rate. This observation is in good agreement with that reported by Shedid (Shedid 2009). However, as apparent from Fig. 8, towards the end of all four experiments, the effect of permeability sequence seems to diminish resulting in almost the same ultimate recovery for all sequences. This behaviour may be attributed to the fact that in the composite samples, there is no opportunity for preferential channelling of the injected CO_2, making the effect of the degree of heterogeneity on the ultimate recovery much less pronounced over longer injection times. Furthermore, capillary forces play no role in influencing the outcome of the miscible floods performed in this work. These characteristics are expected to reduce the effect of axial permeability arrangement on the ultimate recovery considerably. In addition, it is believed that the small diameter of the core segments included in the composite cores have also suppressed the possible effects of their axial arrangement. In other words, the ultimate recoveries for various arrangements might have been different if larger diameter samples were used as that would make the floods to possibly deviate from a 1-D type of displacement.

4 Conclusions

The effect of core-scale heterogeneity on the performance of miscible CO_2 flooding was evaluated systematically using a series of manufactured heterogeneous core samples tested under various flood conditions. The results indicate that the level of heterogeneity (PR) in layered samples strongly affects the recovery with higher PR resulting in lower ultimate RF. In the composite samples, however, while permeability sequence along the sample length may influence recovery during intermediate injection times, it may not affect the ultimate recovery appreciably. As another outcome of this study, it was observed that the miscible CO_2 flooding performs better when injected under the secondary recovery mode where the miscibility is enhanced by facilitating more effective contact between CO_2 and the in situ oil. The experiments evaluating the effect of crossflow in layered samples revealed that crossflow enhances recovery to a degree. However, this effect tends to diminish as the PR of the layered sample increases due to gas channelling dominating the core flooding process.

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Chapter 4

4.1 An Experimental Investigation of Immiscible CO_2 Flooding Efficiency in Sandstone Reservoirs: Influence of Permeability Heterogeneity

AL-BAYATI, D., SAEEDI, A., MYERS, M., WHITE, C. & XIE, Q. 2018. An Experimental Investigation of Immiscible-CO_2-Flooding Efficiency in Sandstone Reservoirs: Influence of Permeability Heterogeneity. *SPE Reservoir Evaluation & Engineering*, 22 (3), 990-997.

An Experimental Investigation of Immiscible-CO_2-Flooding Efficiency in Sandstone Reservoirs: Influence of Permeability Heterogeneity

Duraid Al-Bayati and **Ali Saeedi,** Curtin University;
Matthew Myers and **Cameron White,** CSIRO; and **Quan Xie,** Curtin University

Summary

Reservoir heterogeneity plays a critical role in determining the success of enhanced oil recovery (EOR) processes, but its effect rarely has been comprehensively quantified in the laboratory. This work presents the results of an experimental study on the effects of various carbon dioxide (CO_2) injection modes on immiscible flooding performance in heterogeneous sandstone porous media. Thus, the results of this study can be insightful in overcoming the current challenges in capturing the importance of geological uncertainties in current and future EOR projects.

Coreflooding experiments were conducted for *n* decane/synthetic brine/CO_2 systems at a 9.6 MPa backpressure and at 343 K to attain immiscible flooding conditions [minimum miscibility pressure (MMP) of CO_2 in *n* decane is 12.4 MPa]. For this purpose, two sets of heterogeneous sandstone core samples were assembled with heterogeneity either parallel to (layered samples) or perpendicular to (composite samples) the flow. The results obtained for both composite and layered core samples indicated that heterogeneity tremendously influences the outcome of the CO_2 EOR. Oil recovery decreases dramatically with an increase in the heterogeneity level or permeability ratio (PR). In addition, the crossflow in the layered core sample is found to have a noticeable effect on the ultimate oil recovery (increasing oil recovery up to 5%). Also, it is worth noting that for the composite samples, when we arranged the plugs by putting the low permeability segments closer to the sample outlets, the recovery factor increased. However, regardless of the segment arrangements, the recoveries in composite cores are lower than those obtained from the homogeneous core sample.

Introduction

Background. CO_2 flooding is an effective and widely applied method for EOR and an attractive avenue for geological CO_2 storage. Since 1950, the petroleum industry has implemented considerable research into CO_2 EOR (Whorton and Kieschnick 1950; Whorton et al. 1952; Holm 1959). Recently, injecting CO_2 has captured more interest for both EOR and CO_2 sequestration to reduce gas emissions (Trivedi and Babadali 2006; Saeedi 2012; Kamali et al. 2017; Lei et al. 2016).

The CO_2 flooding process can be categorized as immiscible, near miscible, or miscible displacement on the basis of different reservoir characteristics and pressure conditions (Asghari and Torabi 2008; Cao and Gu 2012; Song et al. 2013). The main effective in situ mechanisms of oil recovery by CO_2 injection are documented to be promoting oil swelling, reducing oil viscosity, reducing interfacial tension (IFT), decreasing oil density, and extracting light components from oil (Holm and Josendal 1974; Seyyedsar et al. 2016). Although CO_2 might not be miscible with most crude oils, it can develop miscibility through multiple contacts. Generally, CO_2 injection can prolong the reservoir life for 15 to 20 years and may recover an additional 15 to 20% of the original oil in place (OOIP) (Yongmao et al. 2004). The effectiveness of an EOR technique depends mainly on how it can improve the microscopic and/or macroscopic sweep efficiencies with respect to the residual/in situ oil (Verma 2015). At the pore level, the displacement of oil by the injected fluid is referred to as microscopic sweep efficiency. In general, microscopic efficiency is controlled by the reservoir pressure, temperature, in situ oil composition, composition and phase behavior of the injected fluid, and the wettability and pore geometry of the rock formation (Sehbi et al. 2001; Meybodi et al. 2011). On the other hand, at the reservoir scale, to reveal how effectively an injected fluid can contact different parts of a rock formation in the horizontal and vertical directions, the macroscopic or volumetric sweep efficiency term is always used. The macroscopic efficiency is dictated by the degree of the reservoir scale heterogeneity present in a formation.

Miscible gas injection generally results in a high microscopic displacement efficiency (>90%) because it promotes the in situ recovery mechanisms referred to earlier (e.g., oil swelling, oil viscosity reduction, and so forth) (Verma 2015). However, several factors limit the application of miscible CO_2 flooding such as the requirements of high pressure to achieve miscibility, sufficiently high geological dip to help stabilize the displacement front, and light oil [i.e., low oil viscosity and high API gravity (30 °API)] (Mungan 1981; Rivas et al. 1994; Jarrell et al. 2002). These restrictions have prompted researchers to investigate the effectiveness of immiscible CO_2 displacement, which is less prone to such limitations. In immiscible flooding, oil recovery may increase because of the relatively low IFT values between the oil and injected gas, thus the minimization of the capillary forces responsible for the entrapment of the nonwet oil phase. The capillary pressure, in addition to the IFT of the fluid system, is controlled by the wettability of the reservoir rock and the pore size distribution of the rock formation. The effect of capillary forces on oil trapping can be characterized by the capillary number (N_C), which is defined as the ratio of viscous force to capillary force. The N_C controls the microscopic displacement efficiency and is defined by Ayirala and Rao (2004) as

$$N_c = \frac{V\mu}{\delta\cos\theta}$$

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where V and μ are the velocity and viscosity of the displacing fluid, respectively; δ is the IFT between the oil and water; and θ is the contact angle that quantifies wettability.

The flow during an immiscible CO_2 displacement condition is dominated by the balance between the capillary and gravity forces. In general, because of the lower density of CO_2 compared with the displaced oil, gravity override might occur, leading to poor sweep efficiency (Al Bayati et al. 2017). The severity of this issue, among others, depends on the reservoir flood length, fluid densities, and reservoir heterogeneity especially, the vertical permeability (Chung et al. 1988). Many studies have addressed different chemically enhanced methods and associated complications of chemical stabilities to control flooding conformance (Kumar and Mandal 2017a, b). However, CO_2 flooding often suffers from an unfavorable mobility ratio leading to viscous fingering that then causes a poor macroscopic displacement efficiency and an early gas breakthrough (Lake and Jensen 1989). Resembling gravity override, the severity of viscous fingering is dictated by reservoir heterogeneity, which has been viewed as a strong controlling factor for performing CO_2 injection (Grigg and Schechter 1997).

For a long time, reservoir heterogeneity has been acknowledged as an important factor governing the reservoir performance and ulti mate oil recovery (Lake and Jensen 1989; Shedid 2009; Bikkina et al. 2016; Ding et al. 2017; Al Bayati et al. 2018a, b). As indicated earlier, during CO_2 EOR, formation heterogeneity might intensify gravity override, viscous fingering, unstable pressure distribution, and channeling or bypassing of the oil, resulting in early breakthrough and leaving most of the residual/trapped oil untouched. Such events could reduce the intended oil recovery substantially and increase the amount of injected CO_2, both of which can make the overall EOR project uneconomical. In the petroleum industry, heterogeneity within a reservoir may be referred to as a variation of permeabil ity, porosity, thickness, saturation, and rock characteristics. Chopra (1988) and Lake and Jensen (1989) indicated that the most promi nent form of heterogeneity involves some form of permeability variation.

Although many field scale numerical simulation studies have been performed to evaluate the effect of heterogeneity on the perform ance of hydrocarbon reservoirs, very limited effort has been focused on evaluating such effects at the core scale or using experiments. Pande and Orr (1994) used an analytical approach to evaluate the recovery from a two layer porous media system. Their model showed a dramatically decreasing recovery with an increase in heterogeneity in the form of the permeability ratio (range of 1.0 to 10.0) between the two layers of the system. Bahralolom et al. (1988) witnessed that the existence of a preferential flow path in visual etched glass heterogeneous models resulted in an early breakthrough and an increased amount of CO_2 consumption for enhanced recovery. Similarly, Al Wahaibi and Al Hadhrami (2011) observed an early breakthrough and a delayed recovery with the presence of heteroge neity in bead packed models. Shedid (2009) conducted a coreflooding study to investigate the effect of different reservoir heterogeneity levels and configurations on oil recovery during miscible CO_2 flooding using core samples constructed with rock segments with three different permeability values. In his experiments, he investigated both layered (heterogeneity in a direction perpendicular to flow) and composite (heterogeneity in the direction of flow) configurations. He concluded that, for layered reservoirs, the highest recovery would be obtained from a medium/high/low permeability arrangement (from top), whereas a low/medium/high permeability sequence (from inlet) resulted in the highest recovery in the composite arrangement. Bikkina et al. (2016) conducted laboratory examinations to assess the influence of permeability heterogeneity on miscible CO_2 EOR performance in water wet layered core samples. Their results showed a recovery of only 0 to 5% after injecting 3 pore volumes (PVs) of CO_2. Lei et al. (2016) conducted CO_2 flooding experiments using a flooding setup containing three parallel coreholders, each containing a sample with a different permeability under both miscible and immiscible conditions. They concluded that the oil recovery of the entire system was dominated by the recovery that they could obtain from the layer with the highest permeability, and injection pressure would not significantly enhance the oil recovery in the continuous CO_2 injection process (i.e., miscible injection had a subtle effect compared with the CO_2 immiscible injection in the multi layer system). Ding et al. (2017) concluded from their experimental work that oil recovery is very sensitive to heterogeneity in a layered flooding system with permeability ratios (PRs) at a range of 1.0 to 15.5. They found that even weak heterogeneity could lead to a large decrease of recovery during both miscible and immiscible flooding. All these previous studies agreed that heterogeneity would inevita bly lead to an early breakthrough and a reduced displacement efficiency as well as increased CO_2 consumption during flooding. In addi tion to all experimental works reviewed thus far, several simulation studies have shown clearly the importance of small scale (subcore) heterogeneity for fluid displacement during flooding (Chaouche et al. 1993; Krause et al. 2011).

This research is dedicated to bridging the existing gap in our knowledge by following a systematic experimental approach to investi gate the effect of core scale heterogeneity on the performance of immiscible CO_2 displacement in sandstone reservoirs. For this pur pose, we performed a series of experiments for quantitative observation of this effect using cores with different permeabilities under a variety of conditions such as the heterogeneity direction (vertical and horizontal) and configuration, the degree of permeability hetero geneity (PR), and the occurrence or lack of crossflow in layered systems.

Experimental Work and Methodology

Coreflooding Equipment, Chemicals, and Test Conditions. A schematic of the experimental apparatus used in this study is shown in **Fig. 1.** The major components of the setup consist of a coreholder (Core Laboratories, FCH Series), three syringe pumps (Teledyne Isco, Model 65D) used for controlling the confining pressure and fluid injections, and two stainless steel transfer cylinders used for stor ing and injecting *n* decane and CO_2. The synthetic formation brine was injected directly with one of the syringe pumps. For recording the inlet and outlet pressures of the coreholder, we used two absolute pressure transducers (Omega Engineering, PX309 2KG5V). We also have used a high precision, dome loaded backpressure regulator (BPR) (Equillibar, U10L Series Precision BPR) to provide a stable pressure regulation and to minimize any fluctuation in pressure readings during the flooding process. This BPR is connected to another syringe pump as the source of applied set pressure. Worth noting is that both confining pressure and backpressure were maintained con stant using two syringe pumps to ensure attaining both an immiscibility condition and a close match between layers of layered core sample during the CO_2 flooding process.

A synthetic formation brine was prepared by dissolving analytical grade salts (Sigma Aldrich) including 2 wt% NaCl, 0.7 wt% KCl, and 0.5 wt% $CaCl_2{\cdot}H_2O$. The *n* decane (99 mol%, Sigma Aldrich) was used to represent the oleic phase, and a high purity CO_2 (99.9 wt%, BOC Gases) was used as the displacing phase during EOR experiments. The coreflood experiments were conducted at the temperature, pore pressure, and confining pressure of 343 K, 9.6 MPa, and 26.88 MPa, respectively. The MMP between CO_2 and *n* decane at 343 K is 12.4 MPa, as reported in the literature (Shaver et al. 2001; Georgiadis and Jackson 2010). Therefore, the selected pore pressure during our experiments was less than the MMP of CO_2 into *n* decane, to achieve an immiscible condition.

Core Samples. Initially, homogeneous sandstone core plugs with different permeabilities were sourced from quarried blocks in the USA. Then, these plugs were used to manufacture samples with either radial or axial heterogeneity that would represent the horizontal or vertical heterogeneity that might be present in a reservoir. A sample with vertical heterogeneity (i.e., a layered sample) is assembled using two half plugs: Each plug is cut parallel to the direction of fluid flow and has a specifically different permeability value. Then, to construct a layered sample, we placed the two halves of each with a different permeability in parallel to form a full diameter hetero geneous plug. Three levels of heterogeneity were attained by changing the PR between the two halves **(Table 1).** Also, placing either an impermeable thin (1 mm) polytetrafluoroethylene (PTFE) sheet or a permeable lint free tissue paper between the two halves of the layered sample assemblies assisted us in evaluating the effect of the crossflow. The tissue paper, in addition to polishing the adjacent sample surfaces, has worked to eliminate any occurrence of void space across the two faces in the cut area. Worth noting is that the 17.23 MPa net effective stress (confining pressure minus pore pressure) applied to the samples together with the insertion of either a lint free tissue paper or a PTFE sheet between the two layers eliminated any possible flow directly through the fracture in the middle of the layered samples. The horizontal heterogeneity (i.e., a composite sample) was constructed by stacking, one after the other, two core segments cut perpendicular to their length from different plugs with different permeability values. For the composite samples, the effect of the axial arrangement of the plug segments on oil recovery was also investigated.

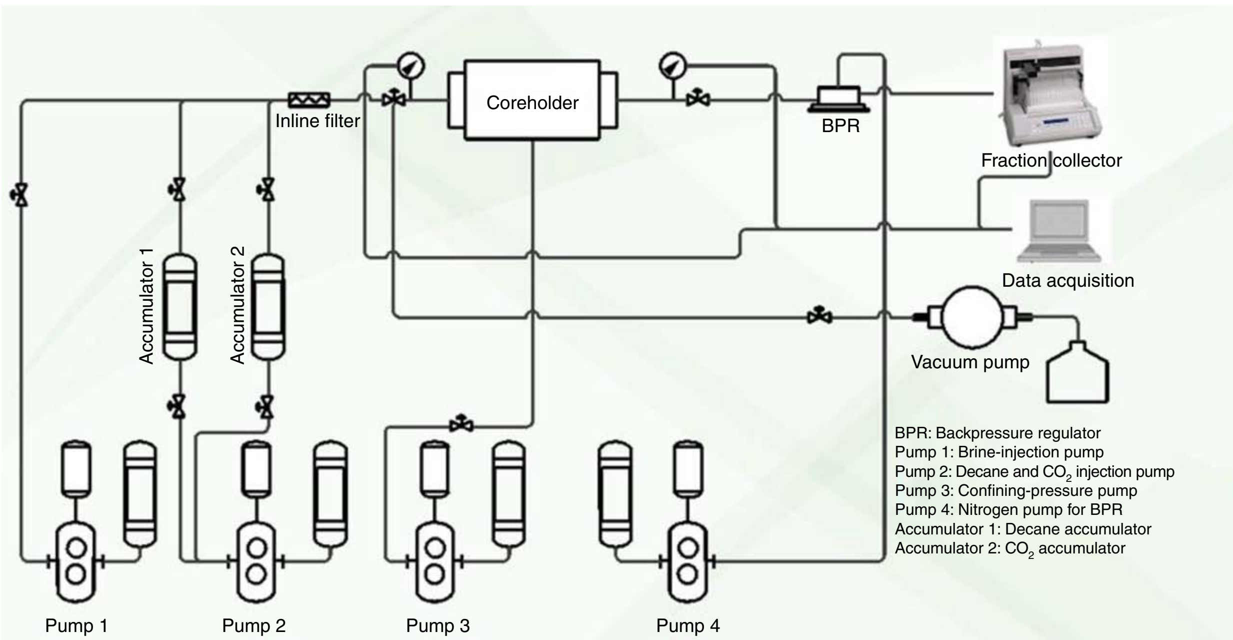

Fig. 1—Schematic of the coreflooding experimental apparatus.

Heterogeneity Level	Lithology	Nominal Permeability of Half Plugs (md)	Nominal Length (mm)	Nominal Diameter (mm)	PR
Weak	Bandera Sandstone	20	76.5	38.1	2.5
	Kirby Sandstone	8			
Moderate	Grey Berea Sandstone	100	76.5	38.1	5
	Bandera Sandstone	20			
Strong	Grey Berea Sandstone	100	76.5	38.1	12.5
	Kirby Sandstone	8			

Table 1 Physical characteristics of manufactured layered samples (PRs).

Experimental Procedure. We have followed a systematic approach in conducting our CO_2 flooding experiments. The procedure fol lowed is given next. First, a temperature controlled Dean Stark apparatus was used to clean the core plugs using a warm methanol and toluene mixture. Then, plug samples were dried in a vented oven for 24 hours at 343 K. By using an automated helium porosi permeameter, measurements of both porosity and absolute permeability of the initial homogeneous samples were obtained before undergoing any core cutting and then flooding. After this, a manufactured core sample (see the Core Samples subsection above) was wrapped with a multilayered sleeve to counteract the CO_2 diffusion and to protect the conventional fluoropolymer elastomer rubber core sleeve [for details, see Saeedi (2012)] from damage during the coreflooding process, and then the sample/sleeve assembly was loaded into the horizontally positioned coreholder. A low confining pressure (5 MPa) was initially applied to the sample, and the temperature was increased to the predefined value; then, the sample was put under vacuum for 12 hours. Synthetic formation brine was then injected into the sample to increase the pore pressure while ensuring that the confining pressure was also controlled by maintaining a net effective pressure of 17.23 MPa. The system was left for saturation for a sufficiently long time to create adsorption equilibrium and to develop pressure and temperature stability throughout the system. The brine permeability of the sample was then measured. After this approximately 5 PV of *n* decane was injected into the sample at 5 cm^3/min to achieve residual water saturation (S_{wr}). In the next step, CO_2 was injected at a constant flow rate of 0.5 cm^3/min into the core sample until approximately 2.5 PV of CO_2 had passed through the sample. The injected CO_2 was established either as a secondary EOR method in which CO_2 was directly injected after residual water saturation achievement or as a tertiary method in which 4 PV of water was injected into the sample first, followed by injecting 2.5 PV of CO_2. Throughout this procedure, the volume of *n* decane that collected at the production side of the setup was recorded.

Experimental Results and Observations

Influence of Vertical-Permeability Heterogeneity (Layered Heterogeneity). We conducted six coreflooding experiments under secondary EOR mode on layered samples (with and without crossflow) using different heterogeneity levels weak, moderate, and strong (Table 1). In addition, for comparison purposes, one coreflooding test was also performed on a homogeneous core sample. Therefore, a PR value of 1.0 represents the homogeneous case. **Figs. 2 and 3** display the oil recovery vs. the PV of CO_2 injected for experiments with and without crossflow, respectively, with each curve representing a specific PR value. As can be seen, the highest ultimate recovery (76.04%) is achieved from the homogeneous core (PR = 1.0) for which the production rate grows fast and remains high even after the CO_2 breakthrough. The primary cause of such an observation is that the CO_2 front moves more evenly in this sample because of the absence of preferential flow paths. Even with the existence of possible gas fingering, the fluid distributions in the flooded part of the sample are expected to remain spatially more uniform even after breakthrough, resulting in a more sustained higher recovery rate with further CO_2 injection. For the other six heterogeneous samples, the recovery profiles before breakthrough resemble that of the homogeneous sample, but after breakthrough, they tend to flatten out earlier resulting in lower final recoveries. One reason for this behavior is the faster flow of gas inside the high permeability layer of the core samples (i.e., flow fingers occur through the preferential paths) that presents the least resistance to flow (Nutt 1982). In other words, the injected CO_2 invades the high permeability layer first, pushing the oil toward the production side of the core. In fact, the larger the PR, the lower the ultimate recovery, which is consistent with the results reported previously by other researchers (Pande and Orr 1994; Zhao et al. 2015; Ding et al. 2017). According to the general material balance between the injection and production sides of the sample, such a behavior would not considerably affect the recovery rate before breakthrough; however, it controls the timing of the breakthrough and also for the post breakthrough stage; the channeling of CO_2 through the higher permeability layer limits the portion of the sample that can be contacted by CO_2 leaving a considerable amount of oil behind in the lower permeability zone. Although, CO_2 channeling would happen, the final volume of the oil recovered in every case reveals that, indeed, some of the recovered oil recovered in our experiments originated from the low permeability layer.

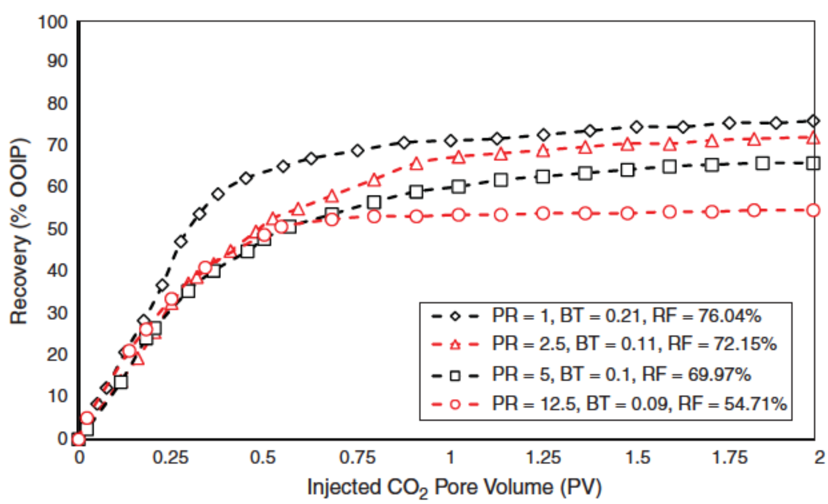

Fig. 2—Effect of layered permeability heterogeneity (with crossflow) on ultimate oil recovery (BT = breakthrough, RF = recovery factor).

The previously discussed results could be elaborated further after using the Duan et al. (2016) observation where they divide the oil recovery profile into two stages during laboratory CO_2 flooding: gas breakthrough stage (a time period directly after breakthrough) and gas channeling stage (after breakthrough when the oil recovery profile begins to flatten out). The shape of the curves included in Figs. 2 and 3 is consistent with the observations made by these researchers. As one can see, the recovery grows with a high rate soon after the gas breakthrough, and most of the post breakthrough oil is displaced before the so called gas channeling stage. In addition to partial flooding by CO_2, other mechanisms such as the extraction of oil using crossflow are expected to have helped with recovering oil from the low permeability layer. The effect of crossflow on recovery will be covered in more detail in the following subsection.

One also can see from Figs. 2 and 3 that the doubling of PR from 2.5 to 5 results in approximately a 4% decrease in the ultimate recovery regardless of crossflow. However, an increase in PR from 5 to 12.5 (a further 2.5 times increase) causes a significant decrease (approximately 15%) in the oil recovery. This demonstrates that, with an increase in PR, the effect of heterogeneity on recovery tends to intensify because the effect of channeling would become highly pronounced. Pande and Orr (1994) made a similar observation while varying PR in the range of 1.0 to 10.0. Zhao et al. (2015) also reported a mere 9% decrease in the ultimate recovery by increasing the PR from 10 to 100. Al Bayati et al. (2017) emphasized the dominance of capillary forces during immiscible CO_2 flooding in homogeneous cores. Burger and Mohanty (1997) also attributed the low recovery of oil from the low permeability section of layered samples to the capillary forces that tend to diminish mass transfer from the low to the high permeability zone.

Influence of Crossflow on Recovery. Crossflow is an important mechanism for increasing recovery during EOR in heterogeneous reservoirs. There are four factors that control the degree of crossflow contribution: viscous, capillary, and gravity forces, along with 66 dispersion (Zapata and Lake 1981; Pande and Orr 1994; Dindoruk and Firoozabadi 1997). The existence of such a mechanism improves recovery by reducing the CO_2 mobility in the high permeability region by promoting two phase flow as well as moving oil from a low permeability layer into the high permeability layer (Pande and Orr 1994). In this study, one primary objective pursued by six of the coreflooding experiments was to achieve a better understanding of the effect of crossflow on the oil recovery in the layered samples under a range of different PR values. In the first three experiments, lint free tissue paper was inserted between the two halves of the layered samples to promote crossflow. For the second set of three experiments, samples resembling the first set were used (to give the same PRs); however, a thin (1 mm) PTFE sheet was inserted between the two halves to prevent any crossflow between them.

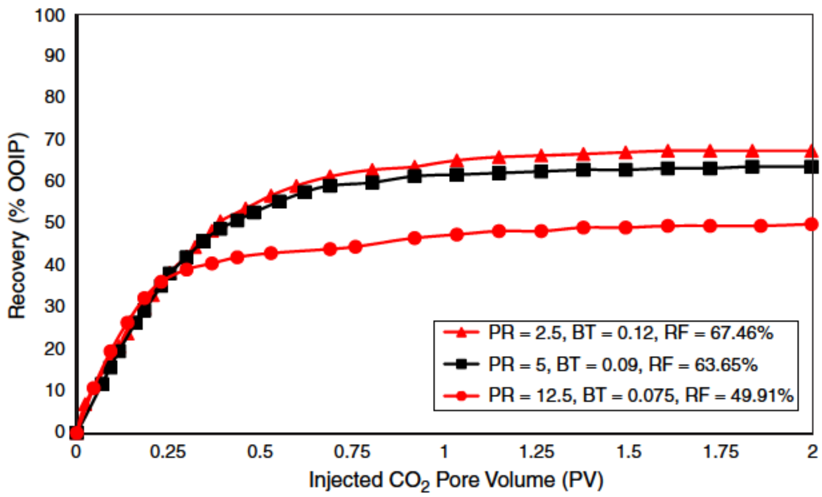

Fig. 3—Effect of layered permeability heterogeneity (without crossflow) on ultimate oil recovery.

Table 2 summarizes the recorded recoveries depicted in **Fig. 4,** which compares the ultimate recoveries achieved for every PR with and without crossflow. As expected, for both scenarios, the recovery decreases dramatically with the increase in PR. Comparing experi ments with and without crossflow, it is obvious that crossflow works against the negative effects of gas channeling, resulting in a higher oil recovery across all PR values (Zapata and Lake 1981; Fayers and Lee 1992; Pande and Orr 1994). This effect is more pronounced for the weak and high heterogeneity levels (i.e., PRs of 2.5 and 12.5, respectively) and less evident for the moderate PR value (i.e., PR of 5). This suggests that, although the effect of crossflow might be masked by a considerable channeling of the injected CO_2 through the high permeability layer as it reduces the amount of additional oil mobilized by crossflow, the result is also controlled by the average absolute permeability of the layered samples (Table 1). Using an analytical approach, Pande and Orr (1994) concluded that, in layered systems, gas channeling has a more pronounced influence on sweep efficiency than crossflow.

Heterogeneity Level	PR	Lithology	Recovery Factor (%) With Crossflow	Recovery Factor (%) Without Crossflow	Difference in Recovery (%)
Weak	2.5	Bandera Sandstone Kirby Sandstone	72.15	67.46	4.68
Moderate	5	Grey Berea Sandstone Bandera Sandstone	65.97	63.65	2.32
Strong	12.5	Grey Berea Sandstone Kirby Sandstone	54.71	49.91	4.79

Table 2 Summary of ultimate oil recovery factors, both with and without crossflow in CO_2 flooding.

Influence of Composite Heterogeneity. We performed two experiments on composite samples investigating the effect of permeability sequence in the direction of flow on the ultimate recovery of secondary immiscible CO_2 flooding. Our composite samples were built using individual plugs with low (L) or high (H) permeability values (i.e., 8 and 100 md, respectively).

Fig. 5 presents the oil recovery vs. PVs of CO_2 injected for the different permeability arrangements of high low high (H L H) and low high low (L H L) along the length of the composite samples. As revealed by the figure, the composite cores with the low permeability plug placed at the outlet yielded a better recovery. For instance, oil recovery of 68.32 and 64.37% is obtained from compo sites with L H L and H L H arrangements, respectively. This behavior might be attributed to the fact that the low permeability plug placed at the outlet of a composite sample (i.e., L H L configuration) could hinder the early gas breakthrough (i.e., delayed break through) causing a more even flooding front to be developed. This observation agrees with the recommendation made by Langaas et al. (1998). These researchers proposed that, for a composite sample, individual plugs must be arranged with decreasing permeability in the flow direction to promote a more uniform displacement and to achieve low residual saturation. In conclusion, Fig. 5 demonstrates that the existence of horizontal permeability heterogeneity in core sample experiments would have a detrimental impact on the ultimate oil recovery.

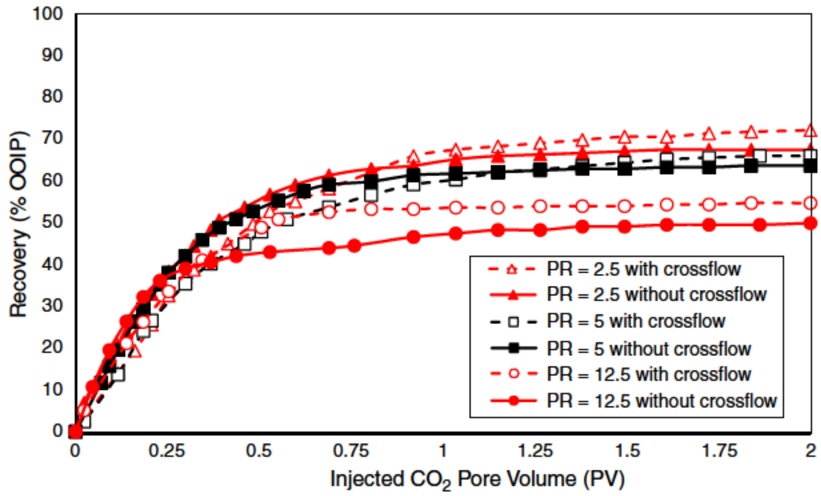

Fig. 4—Effect of crossflow on ultimate oil recovery.

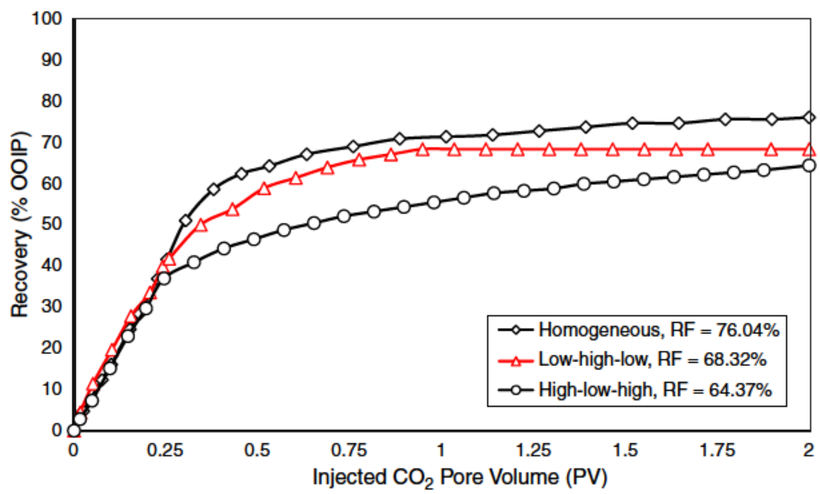

Fig. 5—Effect of composite heterogeneity on ultimate oil recovery.

Conclusions

The effect of core scale heterogeneity on the performance of immiscible CO_2 flooding was evaluated systematically using a series of manufactured heterogeneous core samples tested under various flood conditions. From the recovery profiles, it was determined that, during the times soon after breakthrough, the rate of oil recovery is much higher in a homogeneous core than in a heterogeneous core, regardless of the type and configuration of the heterogeneity. As a result, CO_2 consumption to achieve a specific recovery factor in heterogeneous cores is always larger than that in homogeneous cores. The results also indicate that the level of heterogeneity (PR) in layered samples strongly affects the recovery, with higher PR resulting in a lower ultimate recovery factor. A similar observation is obtained for the composite samples where the permeability sequence along the length of the samples might appreciably influence the ultimate recovery. Furthermore, the experiments evaluating the effect of crossflow in the layered samples reveal that crossflow has an appreciable potential to enhance recovery, but its impact is controlled by the degree of heterogeneity or the PR.

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Chapter 5

5.1 Insights into Immiscible Supercritical CO_2-EOR: An XCT Scanner Assisted Flow Behaviour in layered Sandstone Porous Media

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Insights into immiscible supercritical CO_2 EOR: An XCT scanner assisted flow behaviour in layered sandstone porous media

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ABSTRACT

Reservoir heterogeneity and possible associated crossflow between low and high permeability zones may trigger intrinsic uncertainties to manage and predict reservoir performance. To understand the contribution of crossflow to oil recovery during immiscible CO_2 flooding, we conducted core flooding experiments using layered core samples with the aid of a high-resolution medical X-Ray computed tomography (XCT) scanner. Our results showed that core scale heterogeneity plays a significant role in dictating the spatial distribution of injected CO_2 during flooding thus the oil recovery factor. The experimental results reveal fluid distributions during flooding to be correlated reasonably well with the permeability of each layer. In other words, the higher permeability region of the rock sample contained a higher CO_2 saturation at all times compared with the lower permeability one. X-ray images have facilitated and visually demonstrated the channelling of CO_2 into the high permeability layer leaving a considerable amount of bypassed oil in the low permeability one. We also observed that crossflow indeed arises between layers of the heterogeneous cores suggesting that capillarity plays a noticeable role in increasing oil recovery (i.e. 4.8%). Three dimensional XCT reconstruction of cores together with 2D cross sectional images validated the occurrence of crossflow that would divert CO_2 flow from the high permeability to low permeability zone enhancing oil recovery. The images show that the diverted CO_2 into the low permeability layer would be trapped by associated trapping mechanisms (e.g. snapped-off) and would not form a continuous phase along the length of the sample.

1. Introduction

Carbon dioxide (CO_2) enhanced oil recovery (CO_2 EOR) is a po tentially economical way to boost oil recovery while mitigating greenhouse gas emissions by geo sequestering the injected CO_2 [1,2]. Carbon dioxide injection in hydrocarbon reservoirs can be categorised as miscible, near miscible and immiscible based on in situ reservoir characteristics, temperature and pressure conditions [3 5]. For im miscible CO_2 flooding, oil recovery may increase due to the low inter facial tension (IFT) generated between the oil and injected gas which helps to lower the negative effect of capillary forces. However, since a distinct interface still exists between the fluid phases, the effect of ca pillary forces on an immiscible displacement is still present resulting in a considerable residual saturation of the displaced phase (i.e. low mi croscopic sweep efficiency) [6]. On the other hand, due to an un favourable mobility ratio (M) and density contrast, immiscible CO_2 flooding may result in a low macroscopic (volumetric) sweep efficiency as well due to viscous fingering/channeling and gravity segregation causing early CO_2 breakthrough [7]. Similar to gravity override, the severity of viscous fingering is affected by reservoir heterogeneity which has been viewed as a strong controlling factor for performing immiscible injection ([7 20]). Thus, the full benefit of a CO_2 EOR may be prevented, in part, by a poor understanding of how reservoir het erogeneity may affect the in situ oil and CO_2 saturation distributions as well as the potential effects of crossflow between high permeability and low permeability zones on recovery.

Most forms of heterogeneity may involve a variation in perme ability. There have been a number of numerical simulation studies and analytical approaches evaluating the influence of corescale perme ability heterogeneity on multiphase fluid displacement [21 23]. In addition to the numerical and analytical studies, there have also been a limited number of experimental studies evaluating the influence of the level of permeability heterogeneity on oil recovery factor at the core scale. For instance, Ding et al. [19] demonstrated the sensitivity of oil

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recovery at the core scale to heterogeneity in a two layer medium by varying the permeability ratio (PR) between the layers from 1.0 to 154. Similarly, Al Bayati et al. [24] stressed the impact of heterogeneity at the corescale (i.e. PR in layered cores) in the range of 1.0 12.5 on ul timate oil recovery. They concluded that increasing permeability het erogeneity level leads to increased channelling of fluid in a high per meability zone, thus reduction in oil recovery. Such events could reduce the intended oil recovery substantially and increase the amount of in jected CO_2, both of which can make an overall EOR project un economical. While preferential fluid channeling and fingering can ne gatively impact on recovery from heterogeneous, phenomena such as the crossflow between layers can make a positive contribution to re covery from the layered systems [24].

The mass transfer phenomena or the so called crossflow between layers may occur due to various pore and core scale forces and me chanisms such as the viscous forces [25 27] which may be of high importance in a displacement under favorable mobility ratio. Other influential mechanisms include the diffusion and dispersion [28,29] that may play a considerable role in influencing the displacement if the injected gas is fully or partially miscible with the oil. As the other two forces that may influence crossflow, the gravity and capillary forces may also be dominant during immiscible floods [30,31]. A number of studies have focused on understanding the factors that influence hy drocarbon recovery in layered porous media with some unravelling and quantifying the influence of crossflow during this process. Cinar et al. [32] and Alhamdan et al. [15] found the fluid flow and recovery during floods conducted in a two layer glass bead system under low IFT (i.e. minimal capillary effects) to be dominated by gravity and viscous forces. Other experimental [32,33] and numerical simulation [34,35] studies have demonstrated the dominance of capillary forces in de termining the flow patterns during immiscible displacments in layered systems. Burger et al. [36] indicated that phase behavior of a fluid system plays a significant role in controlling the mass transfer from a bypassed region to a flowing region. Peters et al. [37] performed mis cible flooding experiments and revealed that greater gravitational ef fects would increase crossflow and improve recovery when gravity and viscous forces oppose each other under favorable flooding condition or they may act together under unfavorable flooding condition. Similarly, Zapata and Lake [38] and Debbabi et al. [39] demonstrated that mo bility contrast plays a significant role in improving vertical sweep ef ficiency in a stratified reservoir. Yokoyama and Lake [40] suggested that transverse capillary pressure effects tend to increase oil recovery in stratified media when the transverse capillary number is about 0.1, while an increase in the capillary number to 10 100 would result in complete mixing (i.e. miscibility). Overall, given the influence of dif ferent factors on mass transfer between layers, it could be concluded that crossflow may to some extent counteract the negative effects of layering and improve vertical sweep efficiency [41,32,42]. This would improve recovery by diverting oil from a low permeability layer into a higher permeability one [43]. Crossflow can also reduce channelling through the high permeability regions [44,45,46], by promoting a more pronounced twophase flow and subsequently reducing the mobility of the displacing phase in the high permeability region [22,24].

Many of the core scale features referred to earlier (e.g. crossflow, channeling, viscous fingering) may be better characterised and their effects evaluated if the in situ multiphase flow during experiments could be visualised. Since the early 1960's, several techniques have been adopted for the above purpose. In recent decades, the application of X Ray computed tomography (XCT) for nonintrusive evaluation of variables relating to rock properties and fluid flow visualisation has increased. Many researchers have utilized the XCT technique in their miscible and immiscible core flooding experiments ([46 52]). In gen eral, this technique has the distinct ability to visualise the effects of many core scale phenomena that may be otherwise undetectable by standard practices.

Continuing from our previous work [24] and to gain better insights into the effects of core scale heterogeneity and ensuing fingering, channeling and crossflow during CO_2 immiscible flooding, we imaged the core flooding tests with the aid of an XCT scanner. Doing so has enabled us to qualitatively and quantitatively evaluate the effect of the above factors on the in situ dynamic oil and CO_2 distribution in the core plugs during the experiments and the resultant recovery profiles.

2. Experimental methodology

2.1. Fluid composition and properties

A doped synthetic formation brine (with the in situ viscosity and density of 0.494 mPa.s and 1.04 g/cm^3, respectively) was prepared in the laboratory with dissolving analytical grade salts (SigmaAldrich) including 20 g NaCl, 5 g NaI, 7 g KCl and 5 g $CaCl_2.2H_2O$ in distilled water. The NaI was added to enhance the contrast between different phases in the CT images [48,52]. The core flooding experiments were conducted at a temperature of 343 K, a porepressure of 9.6 MPa, and a net effective stress (i.e. the overburden pressure minus the pore pres sure) of 17.23 MPa. The hydrocarbon phase was represented by n C_{10} (99 mol%, Sigma Aldrich) with a density of 0.7 g/cm^{3}and a viscosity of 0.545 mPa.s under experimental conditions. A high purity CO_2 (99.9 wt %, BOC Gases) was used as the displacing phase during the EOR ex periments. Under in situ conditions, CO_2 would exist in its supercritical state with a density of 0.233 g/cm^3 and a viscosity of 0.0219 mPa.s. The minimum miscibility pressure between CO_2 and n C_{10} at 344 K is 12.6 MPa [53 55]. Therefore, the selected pore pressure during our experiments was below the MMP of CO_2 into n C_{10} to achieve im miscible condition.

2.2. Rock sample properties and preparation procedure

Two homogeneous water wet sandstone core plugs, namely, Grey Berea Sandstone and Kirby Sandstone, with different permeabilities and porosities (i.e. permeability of 0.1 and 0.08 (μm)^2, and porosity of 18% and 23%, respectively) were used in the construction of the hetero geneous (layered) core samples. The nominal length and diameter of the original homogeneous core samples were 76.5 mm and 38.1 mm, respectively. These samples were each cut axially into two half plugs (hemicylindrical). Then a layered sample was simply constructed by placing a Grey Berea hemicylindrical plug on top of a Kirby hemi cylinderical plug (resulting in a heterogeneous sample with a perme ability ratio (PR) of 12.5). We placed either an impermeable thin (1 mm) Teflon sheet or layers of a permeable lint free tissue paper (as suggested by the literature [12,56,57] between the layers to represent samples without and with communicating layers, respectively. This procedure assisted us in evaluating the effect of crossflow on our re sults. The use of either tissue papers or the Teflon sheet also helped with eliminating the possibility of having a prefrential flow path at the joint between the two half plugs. To achieve this important goal we also carefully polished the adjoining surfaces of the half plugs and used a high enough confining stress. The polishing would eliminate any pos sible surface irregularities. The adequate confining stress also would help with securly compressing the adjoining rock surfaces against the tissues or Teflon sheet. It is worth noting that two main reasons for using such material in particular at the sample joint were that firstly both of the tissues and Teflon sheet were adequately flexible and would not be damaged under compression during the experiments. Secondly, none of them would react with CO_2 or any reactive fluid mixures cre ated during the experiments. Further details about our sample con struction procedure can be found elsewhere in the literature [42,58].

2.3. Description of the core flooding experimental setup

A schematic of the experimental core flooding apparatus used in this study is shown in Fig. 1. The experimental setup consists of four main

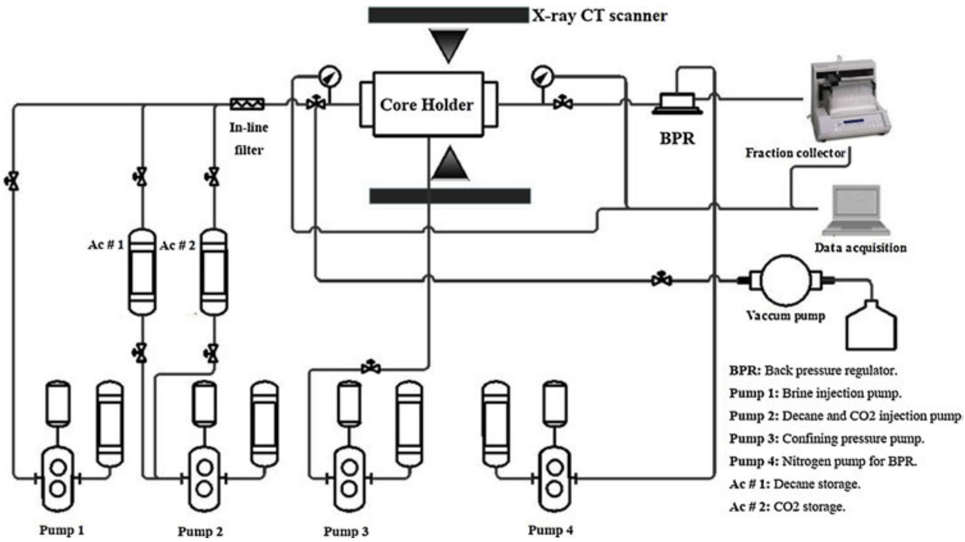

Fig. 1. Schematic diagram of the XCT scanned experimental apparatus.

components: The injection system, the core holder assembly, the pro duction system and the heating system. The injection system itself in cludes two syringe pumps (Teledyne Isco, Model 65D) used for directly injecting the doped brine while n C_{10} and CO_2 were stored and injected through two stainless steel transfer cylinders. A 0.5 µm line filter placed at the inlet of the core holder to prevent any suspended particles from entering into the rock sample. The core holder assembly includes a hydrostatic biaxial type coreholder (Core Laboratories, FCH Series). During the experiments, the pressures at the inlet and outlet ends of the core measured with two high accuracy pressure transducers (Omega Engineering, P X 309 2KG5V). Another syringe pump (Teledyne Isco, Model 65D) was used to maintain the confining pressure applied to the core sample. At the production end of the system, we used a high precision dome loaded backpressure regulator (BPR) (Equillibar, U10 L Series Precision BPR) to have a stable pressure regulation and minimize any fluctuation in pressure readings during the flooding process. A fraction collector was used to collect and record the volumes of fluids produced during the flooding experiments at the production side of the equipment. A heating jacket wrapped around the core holder as well as the fluid accumulators and flow lines to maintain the desired constant temperature during the experiments.

For imaging of the core flooding experiments, a Siemens SOMATOM Dual Energy XCT scanner was used providing visualisation of the fluid distribution in the core sample. With an X ray transparent core holder, X ray images can be made available in real time during the flooding process at regular intervals. The system is also designed to be able to rotate every 0.28 s (helical scanning) allowing for a possible scan speed coverage of up to 23 cm/s with a slice pitch of 0.6 mm. The core holder is made of aluminium and carbon fibre that allows for maximum strength while presenting minimal interference with the X ray during the scans. Polyetheretherketone (PEEK) tubing used in all the connec tion required in the core flooding system as a flexible, easy to cut, and mechanically stable replacement for stainless tubing due to the same reason mentioned earlier for the core. The X ray scanning with an en ergy beam of 140 kV at 1000 mA current is applied to acquire high resolution transversal images to map the fluid distribution at every 600 µm along the Z axis (aligned parallel to the length of the samples) and 100 µm in both X and Y axes (aligned perpendicular to the length of the samples). This scanner created 2D images at different locations along the length of the sample. The fluid distribution of doped brine, n C_{10} and CO_2 can be imaged at different saturation stages. 3D tomo graphy is then done by stacking the 2D images along the third di mension. Avizo software was used for post processing the X ray data and generating 2D and 3D views revealing the fluid distribution in the samples before and after CO_2 flooding.

2.4. Core flooding procedure

Initially, the core samples were cleaned using warm methanol:to luene mixture (50:50%) in a temperature controlled Dean Stark appa ratus. Then the samples were dried in a vented oven for 24 h at 343 K. After this, the porosity and air permeability of initially homogeneous core samples before undergoing any core cutting processes were mea sured using an automated helium porosi permeameter (AP 608, Coretest INC, US). After this, the manufactured core sample (i.e. layered sample with or without interlayers communication) was wrapped in a multilayered core sleeve to counteract the CO_2 diffusion into the con ventional Viton core sleeve and to protect it from damage during the core flooding process [57]. Then the sample sleeve assembly was loaded into the coreholder in the horizontal direction. The experimental net effective stress (i.e. overburden pressure minus pore pressure = 17.23 MPa) initially applied to the sample while the temperature in creased to the predefined value and the sample put under vacuum for a minimum of 12 h. Upon the completion of this step, synthetic brine was injected, and the system left for another 24 h. This was necessary to achieve pressure and temperature stability as well as the establishment of full brine saturation and adsorption equilibrium between brine and rock sample. The brine permeability of the sample was subsequnetly measured by brine injection at a constant flow rate. After this, the ir reducible water saturation (S_{wr}) was attained by injecting five pore volumes (PV) of n C_{10} through the sample at 5 mL/min. It is important to note that this relatively high n C_{10} injection rate was to generate adequate differential pressure across the samples a more effective dis placement of brine by n C_{10} would be achieved. In the next step, As a secondary EOR method, 2.0 2.5 pore volumes of CO_2 were injected into the core sample continuously with the constant flow rate of 0.5 ml/min (determined according to [59] ($LV\mu \geq$ 1.0 5.0, where L is the length of the core in cm, V is the displacing fluid velocity in cm/min, and µ is the displacing phase viscosity in cP) and [60] criteria). Throughout the CO_2 injection period, the volumes of n C_{10} collected at the production end of the setup was monitored and recorded.

In order to obtain and visualise the fluid distribution, we duplicated the above described flooding procedure while XCT images captured with the assistance of the earlier mentioned XCT scanner. In these ex periments to obtain the fluid distribution tomography before and after CO_2 flooding, the CT images were first cropped to obtain a proper re gion of interest (ROI). Noise removals and edge enhancements were conducted using non local means filters. Finally, the images were

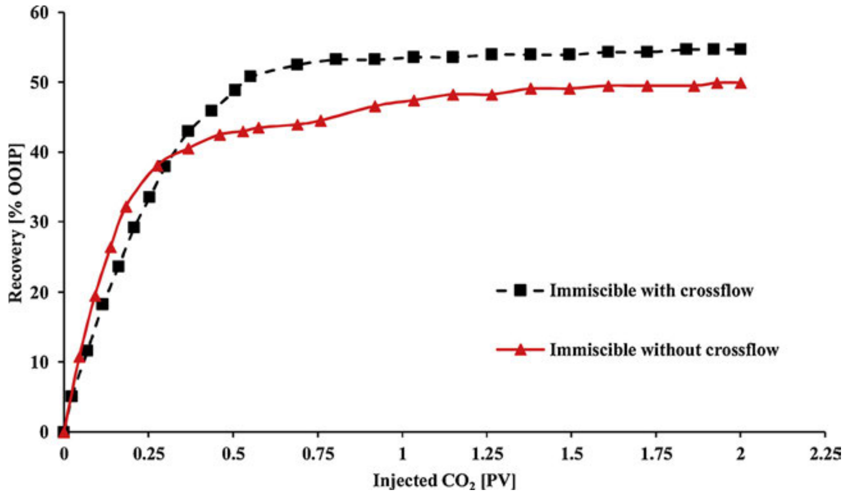

Fig. 2. Immiscible CO_2 flooding in heterogeneous layered sample-oil recovery vs. pore volumes of CO_2 injected.

segmented using a watershed thresholding method, then qualitative and quantitative analysis were conducted.

3. Results and discussion

3.1. Flooding experiments without XCT

We conducted two experiments to explore the role of crossflow on the performance of immiscible CO_2 flooding in layered porous media with a PR of 12.5. These experiments were conducted under secondary EOR mode. It is worth noting that in the layered samples used in this study the high permeability half core was placed on top, under which the buoyancy forces may have had only a minor effect towards the diversion of CO_2 into the high permeability layer, something which would be avoided altogether in samples with noncommunicating layers. From Fig. 2, it is evident that the occurrence of crossflow increases the recovery factor. As can be seen, a recovery factor of 54.7% was re corded with crossflow allowed compared to 49.9% in the case of non communicating layers (i.e. 4.8% incremental oil recovery is attributed to the influence of crossflow). Moreover, it is clear that before break through happens the production rate in the non communicating sample is higher than communicating one due to the higher viscous driving forces and a better conformance control at this stage. However, after the breakthrough, most of the oil from high permeability zone re covered leaving the low permeability untouched due to the non oc currence of crossflow.

3.2. XCT imaged flooding experiment with crossflow

As indicated earlier, XCT imaged experiments were conducted pri marily to better understand fluid flow and saturation distribution during flooding, which could help to visualize the effect of crossflow on oil recovery in the layered samples. For this purpose, we ran an ex periment using one of the heterogeneous samples constructed (PR = 12.5) where crossflow was promoted by placing a tissue paper between the two halves of the sample. Fig. 3 depicts a 3D tomography of fluid distribution before and after CO_2 flooding of a cropped 3D portion of the sample. Before CO_2 flooding, Fig. 3 shows the presence and distribution of n C_{10} across the entire heterogeneous core sample. Whereas, after CO_2 flooding, the prevailing spatial distribution of CO_2 in the higher permeability layer (i.e. channeling) is observed. This is because the CO_2 tends to preferentially fill regions of high permeability and bypass low permeability regions, leading to much of the oil left bypassed in the low permeability region. It can be also observed (Fig. 3) that any CO_2 entered the low permeability layer is trapped as a discontinuous phase. We also have used Avizo software to extract the data from the 3D images to quantitativly demonstrate the contribution of each layer to n C_{10} recovery along the core sample (Fig. 7). As can eb seen from Fig. 7 much of the recovered n C_{10} (˜82.0% of the original n C_{10} in high permeability layer) comes from high permeability layer with a small contribution from the low permeability one(˜27.0% of the original n C_{10} in low permeability layer). Fig. 4 shows 2D cross sec tional X ray images in the XY plane at different distances from the sample inlet before and after CO_2 flooding. The fluid distribution vi sualised by 2D images confirm the conclusions derived from the 3D images (i.e. a uniform distribution of n C_{10} before CO_2 injection and chaneling of injected CO_2 through the high permeability layer). To confirm the effect of crossflow on fluid distribution and recovery, we evaluated the CT values in each layer close to the interface between them at different experimental stages (i.e full brine saturation and then in the presence of decane before and after CO_2 flooding). Fig. 5 shows that the mean CT numbers at the CO_2 flooded stage in the top layer (high permeability) are lower than the mean CT number of the decane saturated stage which is expected as most of the decane would have been recovered in this layer by the end of this stage. While we noticed that the final mean CT numbers at the CO_2 flooded stage in the low permeability layer after CO_2 flooding (Fig. 6) is higher than that of the decane saturated stage. This may suggest that some of the brine (which has higher CT values due to dopant addition) with the assistance of capillary forces diverted from the high permeability layer to replace both decane and CO_2 in low permeability layer due to both of wett ability preference of the sample and the occurrence of crossflow. The behaviour of the results in Fig. 6 maybe also explained according to the CO_2 n C_{10} phase behaviour presented by Shaver et al. [54]. At our ex perimental condition, the equilibrium decane phase density in the binary mixture of CO_2 and n C_{10} (i.e. decane and associated CO_2) is higher than pure decane density. This suggests that the high mean CT values of CO_2 flooded sample in low permeability layer could be due to continuous mixing processes at this layer (CO_2 still mixing with the decane).

It is worth noting that the overall mean CT numbers of the top layer are higher than those for the bottom layer. This could be due to the higher porosity of the bottom layer. One can conclude from the above discussions that the heterogeneity in vertical direction indeed affects the remaining oil saturation and its distribution significantly, thus the oil recovery. Besides, the occurrence of crossflow helped with addi tional oil recovery. However, channeling in highly heterogeneous porous media may mask the positive impact of crossflow as it reduces the amount of additional oil mobilized by crossflow. This observation is in line with the analytical approach of Pande and Orr [22] which

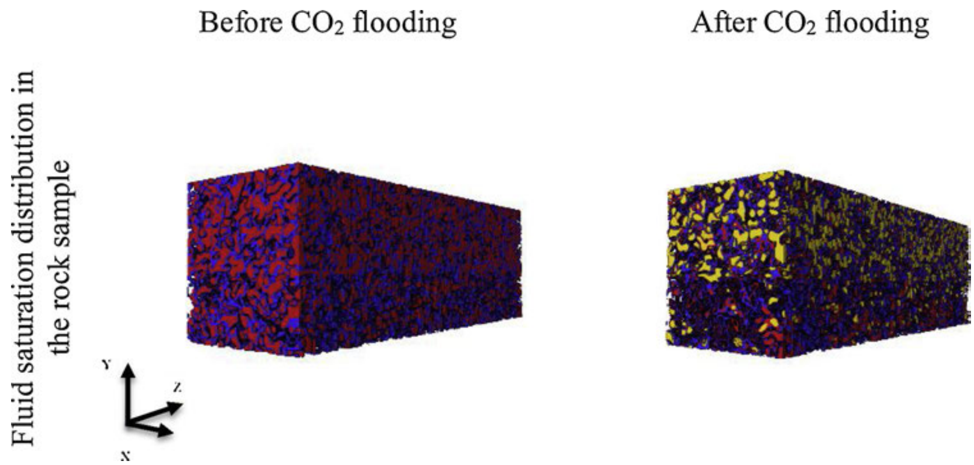

Fig. 3. 3D topology of all fluids right before and after CO_2 flooding in the layered sample-with crossflow after cropping sample in all three (XYZ) directions. Blue: brine, Red: n-C_{10}, and Yellow: CO_2. (20*20*50 mm in XYZ).

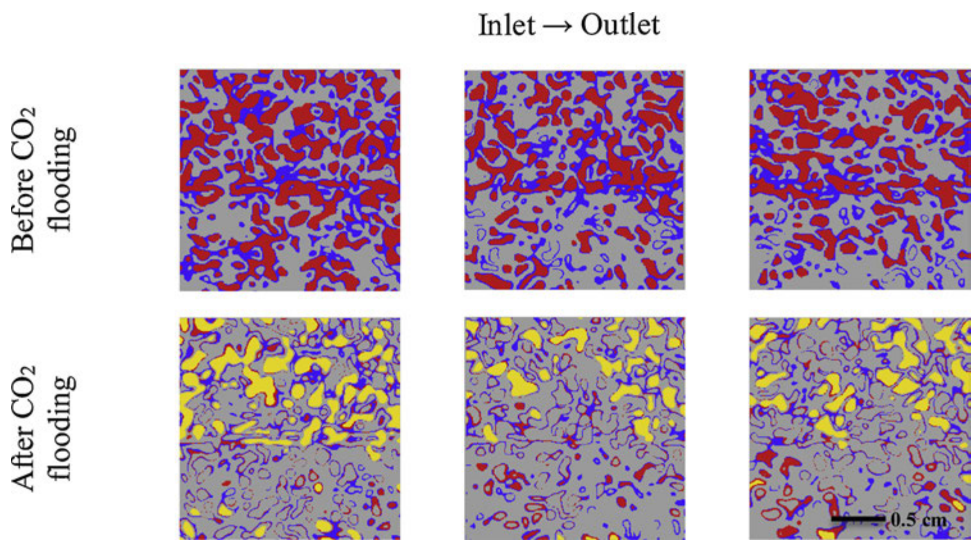

Fig. 4. 2D images in XY direction of fluid distribution before and after CO_2 flooding in the layered sample-with crossflow. Grey: rock sample, Blue: brine, Red: n-C_{10}, and Yellow: CO_2.

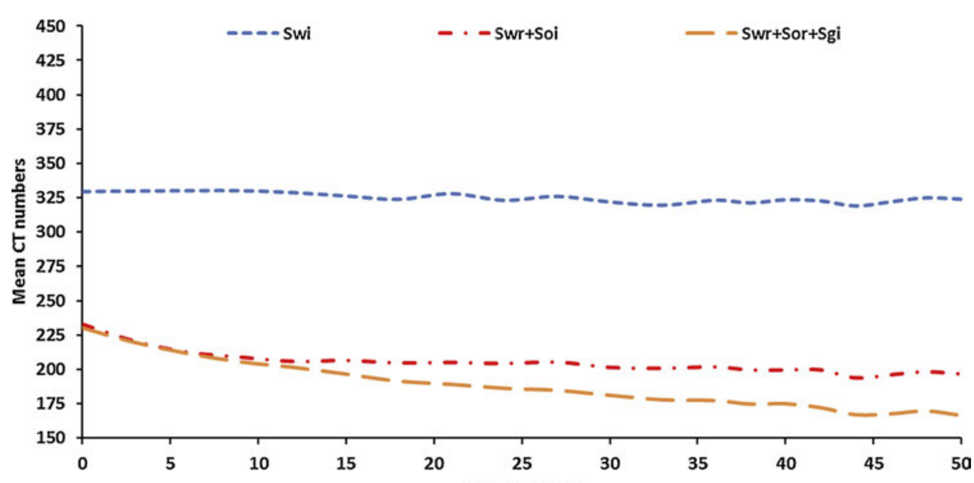

Fig. 5. Mean CT numbers for immiscible CO_2 flooding with crossflow - top layer. S_{wi}: brine saturated sample, $S_{wr} + S_{oi}$: Decane saturated sample + residual water saturation, and $S_{wr} + S_{or} + S_{gi}$: CO_2 flooded sample. Mean CT number = (CT @ each saturation level minus CT @ dry rock sample).

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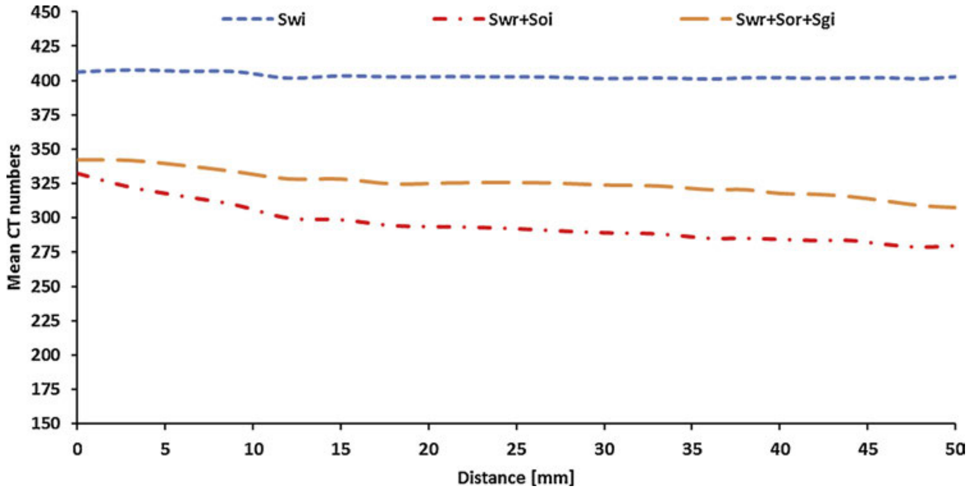

Fig. 6. Mean CT numbers for immiscible CO_2 flooding with crossflow- bottom layer. S_{wi}: brine saturated sample, $S_{wr} + S_{oi}$: Decane saturated sample + residual water saturation, and $S_{wr} + S_{or} + S_{gi}$: CO_2 flooded sample. Mean CT number = (CT @ each saturation level minus CT @ dry rock sample).

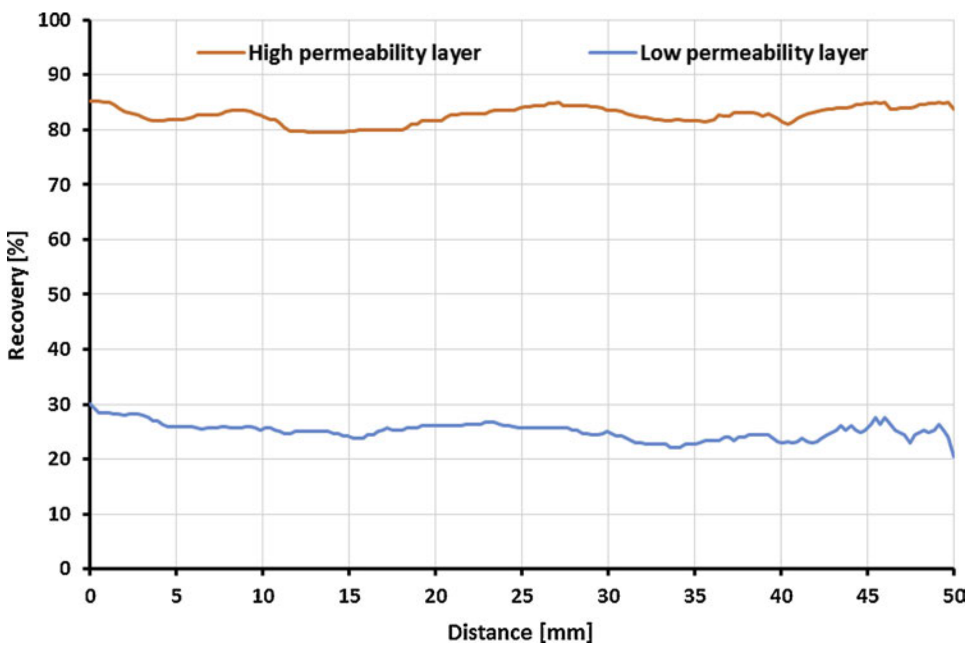

Fig. 7. Recovery factor of n-C_{10} in high and low permeability layer when crossflow permitted between layer (data extracted from 3D images processed using Avizo software).

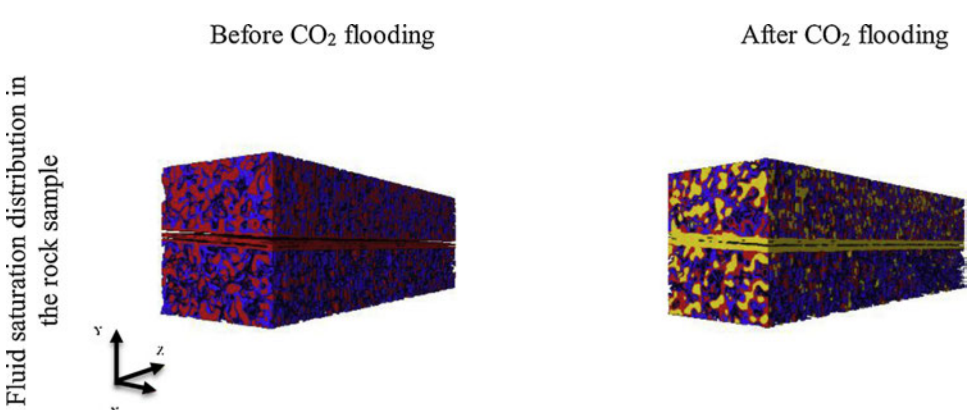

Fig. 8. 3D topology of all fluids right before and after CO_2 flooding in the layered sample-without crossflow after cropping sample in all three (XYZ) directions. Blue: brine, Red: n-C_{10}, and Yellow: CO_2. (20*20*50 mm in XYZ).

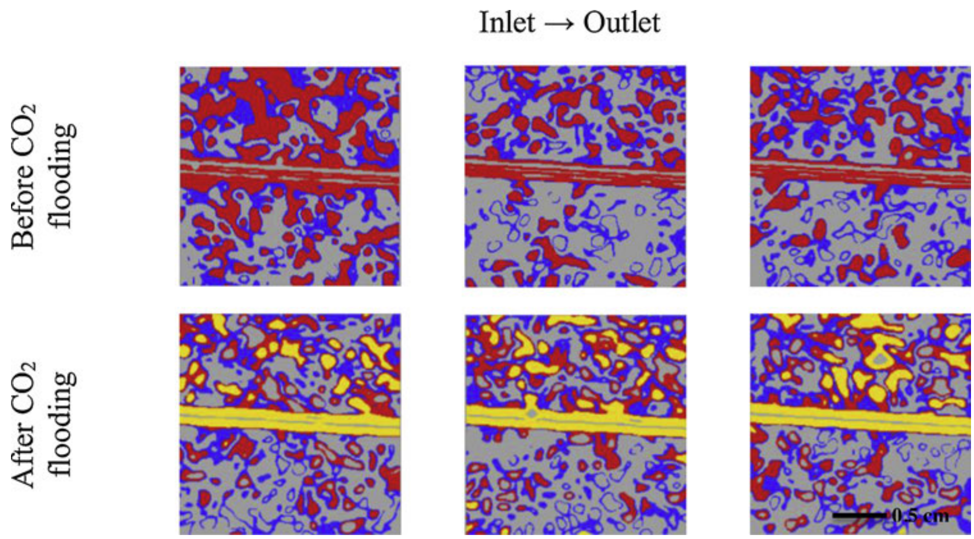

Fig. 9. 2D images in XY direction of fluid distribution before and after CO_2 flooding in the layered sample-without crossflow. Grey: rock sample, Blue: brine, and Red: n-C_{10}. (Slice 1: close to the inlet, and slice 9: close to the outlet of the sample).

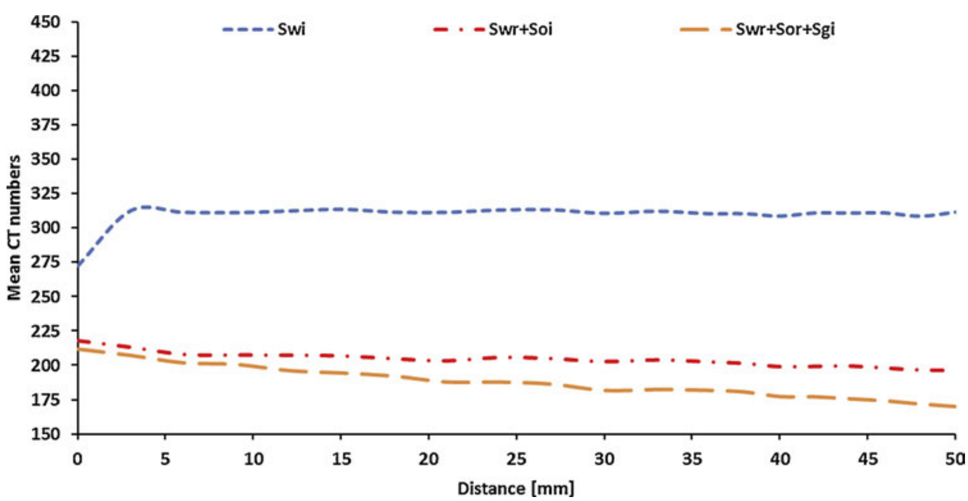

Fig. 10. Mean CT numbers for immiscible CO_2 flooding with crossflow-top layer. S_{wi}: brine saturated sample, $S_{wr}+S_{oi}$: Decane saturated sample + residual water saturation, and $S_{wr}+S_{or}+S_{gi}$: CO_2 flooded sample. Mean CT number = (CT @ each saturation level minus CT @ dry rock sample).

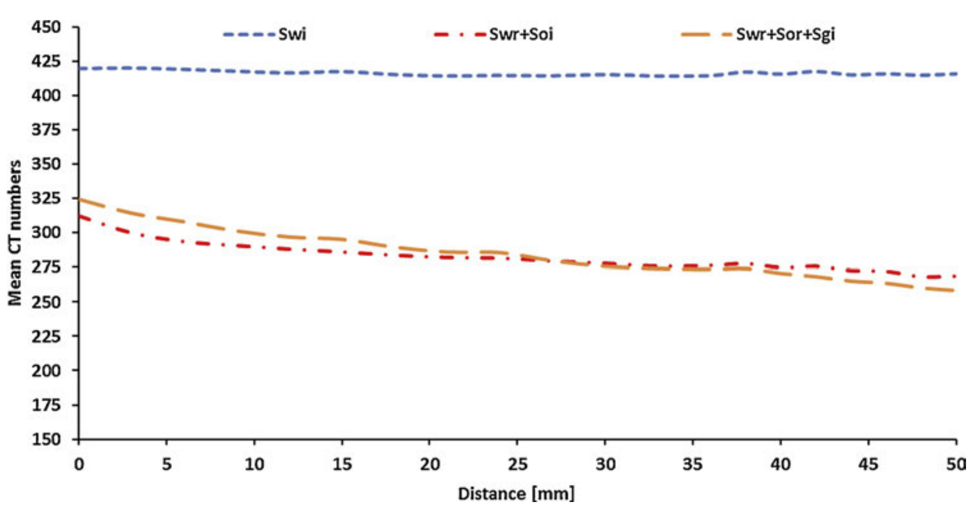

Fig. 11. Mean CT numbers for immiscible CO_2 flooding with crossflow-bottom layer. S_{wi}: brine saturated sample, $S_{wr}+S_{oi}$: Decane saturated sample + residual water saturation, and $S_{wr}+S_{or}+S_{gi}$: CO_2 flooded sample. Mean CT number = (CT @ each saturation level minus CT @ dry rock sample).

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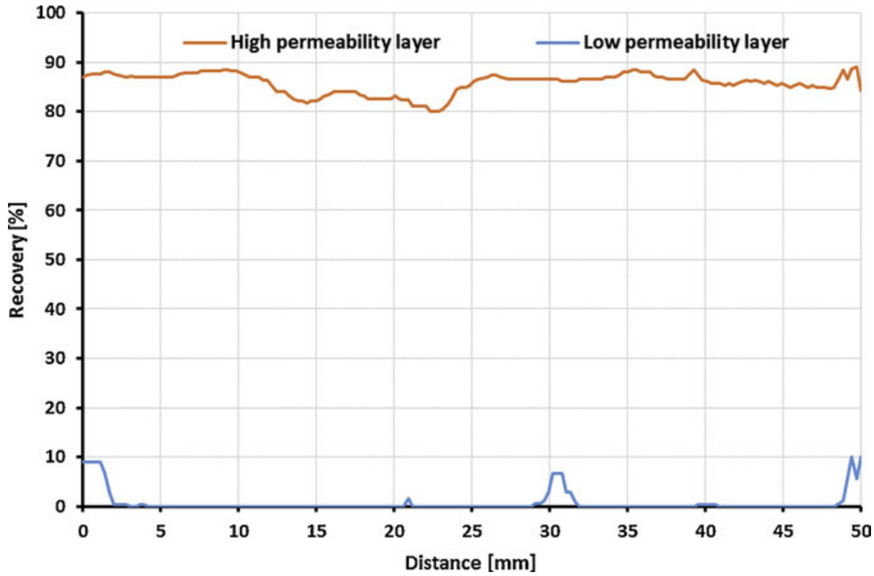

Fig. 12. Recovery factor of n-C_{10} in high and low permeability layer when crossflow prevented between layer (data extracted from 3D images processed using Avizo software).

concluded that in layered media, gas channeling may have a higher impact on sweep efficiency than crossflow.

3.3. XCT imaged flooding experiment without crossflow

To further establish the importance of crossflow in oil recovery during immiscible CO_2 flooding, the X ray CT imaging results obtained in the non communicating layer case (where Teflon sheet was placed between the two half cores) is discussed in this section.

Fig. 8 shows a 3D tomography of fluid distribution before and after CO_2 flooding for the above sample after cropping them in all three (XYZ) directions. Before CO_2 flooding, the images show the presence and distribution of the n C_{10} across the entire core sample. Moreover, after CO_2 flooding, channeling of CO_2 through the high permeability layer is clearly evident leaving the low permeability layer untouched. This is mainly because of the sample heterogeneity and the existence of a barrier between layers preventing crossflow. Here, we have also extracted the data from the 3D images to again quantitativly and demonstrate the contribution of each layer to n C_{10} recovery (Fig. 12) as well as reveal the influence of crossflow along the core sample. As can be seen in Fig. 12, almost all of the recovered n C_{10} (~87.0% of the original n C_{10} in high permeability layers) comes from high permeability layer with a negligible contribution from low permeability layer (< 1.0% of the original n C_{10} in low permeability layers). It is worth noting that there are small fluctuaions in n C_{10} recovery in low permeability layer at both ends (inlet and outlet) of the sample which may be attributed to the capillary end effect. Fig. 9 shows 2D cross sectional images in XY direction at different distances from the sample inlet before and after CO_2 flooding These figures further confirmed the findings from

Fig. 8. This further confirms that heterogeneity in vertical direction certainly affects the remaining oil saturations and its distribution significantly, thus the oil recovery. Moreover, to confirm the influence of the absence of crossflow on fluids distribution, similar to the previous experiment (where crossflow was allowed), we examined the mean CT values in each layer close to the interface between them at different experimental stages (i.e full brine saturation and then in the presence of decane before and after CO_2 flooding). The acquired mean CT numbers for high permeability layer and low permeability one is drawn in Fig. 10 and Fig. 11. For the high permeability layer, Fig. 10 shows that the mean CT numbers at the CO_2 flooded stage in the top layer are lower than the mean CT number of the decane saturated stage which demonstrate the high recovery of decane in this layer. Whereas, in the low permeability layer, the mean CT numbers at the CO_2 flooded stage match the CT numbers at the decane saturation stage which reflects the no change in the fluid saturations in this zone. Comparing the mean CT numbers of low permeability layer with and without crossflow, it is evident that crossflow considerably contributes to the total oil recovery and works against the negative effects of gas channelling. This result is in conformance with the previously published literature [22,24,30,38,42].

4. Implications and conclusions

Reservoir heterogeneity is a critical feature of a hydrocarbon reservoir that impacts on displacement performance, thus hydrocarbon recovery [15,17,19,32,42]. Building upon our previous work, we performed core flooding tests imaged with the aid of an X ray CT scanner to generate 3D tomography of fluid distributions at different flooding stages. The effect of heterogeneity on the performance and distribution of CO_2 flooding at the core scale was evaluated in a systematic way using a specially constructed heterogeneous layered core sample with a permeability ratio of 12.5 between its two layers.

The experimental results reveal that the above mentioned core scale permeability heterogeneity strongly controls the CO_2 flow path and distribution thus ultimate oil recovery. The channelling of CO_2 into the high permeability layer leaving an appreciable amount of oil untouched in the low permeability layer is visually demonstrated using X ray images. The XCT technique also enabled us to present new evidence towards the potential impact of crosflow on in situ fluid distribution and the recovery process. They reveal that indeed crossflow has a reasonable potential to enhance recovery, but its effect is counteracted by significant channelling of CO_2 through the high permeability layer that reduces the amount of incremental oil mobilised by crossflow. The experimental results also indicated that the CO_2 entered the low permeability layer due to crossflow would become trapped (snapped off) as a discontinuous phase along the length of the sample. Moreover, the results demonstrate that the capillarity may play a role by increasing oil recovery potential in the layered samples with crossflow.

Acknowledgements

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Chapter 6

6.1 Insight Investigation of Miscible $_{SC}CO_2$ Water Alternating Gas (WAG) Injection Performance in Heterogeneous Sandstone Reservoirs

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Insight investigation of miscible $_{SC}CO_2$ Water Alternating Gas (WAG) injection performance in heterogeneous sandstone reservoirs

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ABSTRACT

In this manuscript, we present the results of a systematic approach to investigate the impact of core scale heterogeneity on the efficiency of miscible CO_2 water-alternating-gas (WAG) flooding performance. Both vertical (by layering two axially-cut half plugs with differing permeability) and horizontal (stacking two smaller core samples with differing permeability in series) heterogeneities are explored. In the layered or vertically heterogeneous sample, the permeability ratio (PR) defines the ratio between the permeability values of each half plug. Our special sample construction technique using either a thin impermeable Teflon sheet to prevent flow communication or a thin tissue to promote flow communication has enabled us to investigate the effect of crossflow between half plug on the performance of the WAG flood. For the stacked composite or the horizontally heterogeneous core samples, short cylindrical core segments were used each with a different permeability value. We have also investigated the effect of the EOR injection mode (i.e. secondary vs. tertiary) on our results. For this study, core flooding experiments were performed using n-C_{10}, brine and CO_2 at a temperature of 343 K and a pressure of 12.4 MPa.

The results obtained for homogeneous, layered and composite samples indicate that CO_2 WAG flood performs better in all cases and achieves the highest recovery factor (RF) when conducted under the secondary mode (e.g. homogeneous: 93.4%, layered: 74.0%, and composite: 90.9%) compared with the tertiary mode (e.g. homogeneous: 74.2%, layered: 64.1%, and composite: 71.3%). For the layered samples, it was found that the oil recovery decreases noticeably with an increase in the permeability ratio (PR). For instance, RFs of 93.4%, 90.1%, 78.8%, and 74.0% correspond to PRs of 1, 2.5, 5, and 12.5, respectively. In contrast to our previous findings with continuous CO_2 flooding which showed that crossflow enhances recovery in layered samples, for this study using WAG, crossflow was found to negatively affect the RF. Such an outcome may be attributed to the conformance control achieved by WAG flooding which would be more pronounced in the case of non-communication layers (i.e. no cross flow). In other words, the higher oil recovery of WAG flooding in a non-communicating system may be due to the dominance of viscous forces and, to a lesser extent, the vanishing effect of gravity forces that tend to reduce sweep efficiency. The effect of composite heterogeneity on the RF was also investigated with the results showing that the permeability sequence along the length of a composite sample has a noticeable but more subtle impact on RF.

1. Introduction and background

Since the mid 20th century, many researchers have investigated the suitability of CO_2 as an EOR agent and the field applications also resulted in favourable outcomes [1 4]. With declining oil reserves worldwide, CO_2 flooding for EOR has great potential for more widespread use. Furthermore, in more recent years, it has been pointed out that CO_2 injection into oil reservoirs can also be an effective approach for mitigating the global warming and reducing greenhouse gas emissions [5 7]. In fact, the application of CO_2 for EOR (CO_2 EOR) may be considered as an added advantage in helping to offset the cost associated with CO_2 geo sequestration processes making them economically more attractive.

Generally, CO_2 injection can prolong a reservoir's life by 15 20 years and may recover an additional 15 20% of the original oil in place [8]; this is mainly due to the high microscopic displacement efficiency

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of the CO_2 flooding [9,10]. What makes a CO_2 displacement microscopically efficient is the continuous mass transfer and compositional exchange between CO_2 and the reservoir oil which would then favourably influence the fluid densities and viscosities [11,12]. Another effective mechanism is the reduction in the interfacial tension (IFT) under miscible CO_2 flooding. The fact that CO_2 oil IFT (i.e. IFT $\approx$ 0 under miscible conditions) is substantially lower than water oil IFT enables the CO_2 to extract more oil from the reservoir pore space that may not be otherwise recoverable by water alone. On the other hand, CO_2 injection often suffers from poor macroscopic displacement efficiency resulting from its extremely low viscosity and relatively low density as well as the inevitable heterogeneity present in most reservoirs [13,14]. The high viscosity contrast of the flood makes the mobility and consequently flood profile control a major concern for the successful application of CO_2 EOR. With the lack of control, early CO_2 breakthrough, unstable pressure distribution, viscous fingering, channelling and bypassing of the oil would work against the outstanding microscopic sweep efficiency of the flood resulting in reduced oil recoveries.

From the above discussion it is evident that the capillary number and mobility ratio are two major dominating factors controlling the efficiency of a flooding process during oil recovery. In other words, the overall efficiency of a displacement process can be increased by either increasing the capillary number and/or decreasing the mobility ratio, both of which are the focal point of many enhanced oil recovery methods [15]. With the above in mind, research efforts continue to improve the displacement profile control (conformance control) techniques during gas flooding in general. These efforts led to the development of the Water Alternating Gas (WAG) flooding process in 1958 [16]. As pointed out by many researchers, using a miscible WAG flooding both of the capillary number and mobility ratio can be manipulated favourably resulting in a significant portion of the residual oil to become economically recoverable. During a miscible CO_2 WAG process for instance, the alternating injection of water reduces the relative permeability to CO_2 which then lowers the mobility of the flood enhancing the overall macroscopic displacement efficiency putting the outstanding microscopic sweep power of the miscible CO_2 flood in work across a larger volume of the reservoir. In other words, the miscible WAG flooding combines the improved microscopic displacement efficiency achievable with CO_2 injection with the reasonable macroscopic displacement efficiency that may be obtained with water flooding.

The literature indicates that first WAG flooding process was applied in Canada (Caudle and Dyes [16]. Caudle and Dyes [16], Beeson and Ortloff [17], and Holloway and Fitch [18] published some of the earliest literature on the application of WAG. In general, for the case of CO_2 EOR, all published literature indicate that WAG flooding is a more effective injection technique than injecting either water or CO_2 continuously [19 22]. It is worth noting that being more effective does not necessarily equate to a higher eventual recovery factor. For instance, Kulkarni and Rao [23] concluded that although in their experiments continuous CO_2 injection resulted in higher recovery factors, WAG was found to be more effective when recovery factors were normalised by the volume of the CO_2 injected in each case. In other words, higher eventual recovery of the continuous CO_2 injection came at the cost of injecting larger CO_2 volumes (which is generally more costly to inject compared to water). An extensive literature review and analysis of WAG field applications, laboratory and simulation works are already available in the literature [24 28]. Christensen, Stenby [24], who reviewed over 50 field projects, reported that in general WAG flooding results in 510% increase in the oil recovery. According to their review, about 79% of the reviewed WAG field applications were found to operate under miscible conditions and about 57% have been applied in sandstone reservoirs. There have also been many studies investigating factors that affect the WAG injection process efficiency such as fluid properties, trapped gas, wettability, reservoir heterogeneity, injection schemes and WAG related parameters such as WAG ratio, cycling frequency, slug size and injection rates [29 48].

One important aspect of a hydrocarbon reservoir that impacts on its hydrocarbon yield is heterogeneity. Heterogeneity is a fact of life in almost all hydrocarbon reservoirs discovered worldwide. In the petroleum industry, reservoir heterogeneity may refer to a variation of permeability, porosity, thickness, saturation, wettability and other rock characteristics. Stratification and reservoir permeability heterogeneity have long been recognized as the critical aspects affecting reservoir performance and the oil recovery process [49 51]. Reservoir heterogeneity impacts on flood conformance and sweep patterns during an EOR process by intensifying fingering and channelling of the injected fluid resulting in early breakthrough and reduced sweep efficiency. Numerical simulations confirm this and suggest that higher vertical to horizontal permeability ratios adversely affect oil recovery in a WAG process [52]. As reported by Gorell [52], in a non communicating layered system, the vertical distribution of CO_2 during WAG displacement is strongly influenced by permeability contrast and the flow into each layer is essentially proportional to the overall system permeability and thickness and is almost independent of the WAG ratio. During displacement processes, gravitational forces tend to have minimal effect on the performance of the flood in the horizontal plane. Many reservoirs tend to be relatively homogeneous in this plane. Therefore, in a majority of reservoirs, horizontal sweep efficiency of the flood is most affected by the stability of the displacement front in this plane as controlled by the mobility ratio. On the other hand, the vertical sweep efficiency, in addition to the mobility ratio, is impacted by gravitational segregation and reservoir heterogeneity which compared to the horizontal direction are much more highly pronounced in the vertical direction.

To varying degrees at both the reservoir and core scale, recovery from heterogeneous layered porous media is influenced by the cross flow between the layers that may occur perpendicular to the main flow direction (often horizontal). To the best of our knowledge, all of the existing literature investigating the effects of crossflow have focused on continuous fluid injections and there is no similar study conducted for WAG floods. Viscous, capillary, gravity and dispersive forces all influence the crossflow phenomenon [26,53 55] that can favourably affect sweep efficiency even in the presence of low vertical to horizontal permeability ratios. The positive contribution of crossflow during a gas flood is attributed to physical dispersion, reduced gas channelling through the high permeability layer and delayed gas breakthrough which are all in turn controlled by permeability contrasts between layers and flood mobility ratios.

To date, research focusing on the experimental evaluation of heterogeneity effects on recovery during CO_2 injection is very limited and is even more limited with regards to CO_2 WAG flooding. Shedid [56] conducted a core flooding study to investigate the effects of different core scale heterogeneity arrangements (i.e. permeability sequence in vertical and horizontal directions) on oil recovery during miscible CO_2 flooding. At the completion of the study, he concluded that for layered samples (i.e. vertical heterogeneity), the highest recovery would be obtained from a medium high low permeability arrangement (from top) whereas in the composite samples (i.e. horizontal heterogeneity) a low medium high permeability sequence (from inlet) resulted in the highest recovery. Zhao, Hao [57] experimentally examined oil recovery in layered samples each made up of two half plugs of the same size (similar to those used in our work). In their samples, the permeability ratio (PR) between the two layers were set at 10, 30, 100, and 500. They observed that the pressure drop during CO_2 displacement decreases dramatically with increases in the PR and the remaining oil in the low permeability layer was not effectively displaced due to the preferential mobility of CO_2 in the higher permeability layer. Zhou, Al Otaibi [58] investigated the impact of both gravity override and permeability ratio on oil recovery performance of CO_2 injection using a dual core laboratory flooding apparatus. They found that permeability contrast to have a significant impact on oil recovery and the injected

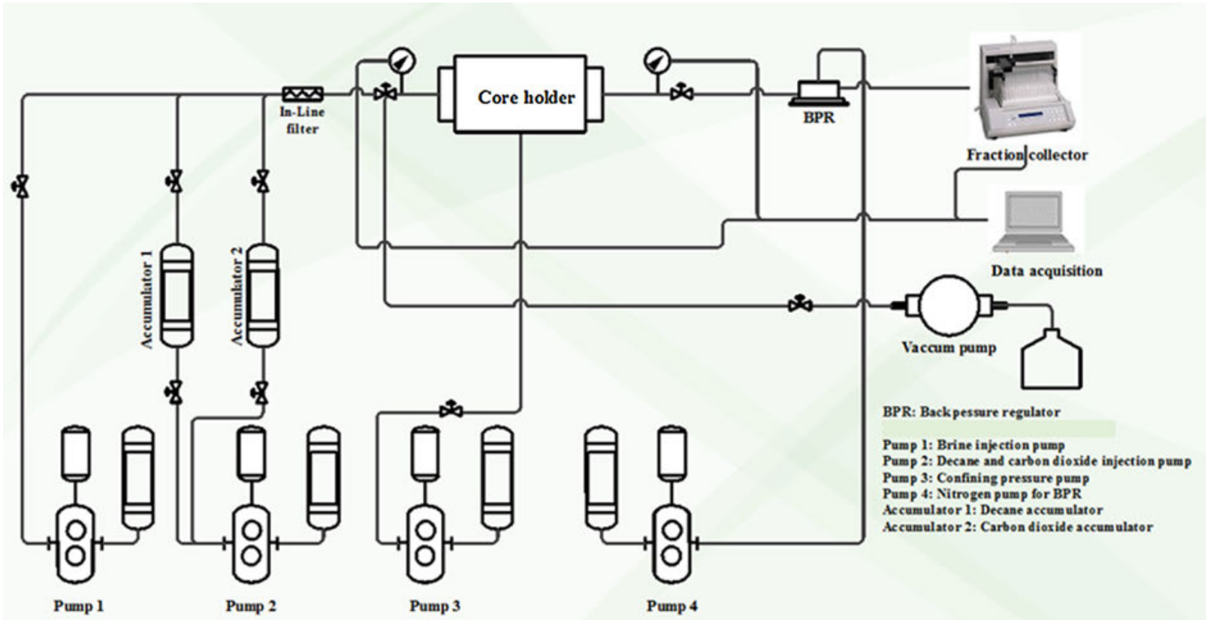

Fig. 1. Schematic of core flooding setup.

CO_2 to bypass through the high permeability core leaving the low permeability one poorly swept. Bikkina, Wan [59] conducted another laboratory investigation to evaluate the influence of wettability and permeability heterogeneity on the performance of miscible CO_2 EOR in layered core samples. Their results showed a recovery of only 0 5% after injecting three pore volumes of CO_2. Ding, Yuan [22] found the oil recovery during miscible and immiscible CO_2 flooding experiments to be very sensitive to the core scale heterogeneity in a two layer system by changing the permeability ratio (PR) between the layers in the range of 1.0 154. Their findings showed that even a weak heterogeneity can lead to a large decrease in the recovery of miscible CO_2 flooding. Si milarly, Al Bayati, Saeedi [60] and Al Bayati, Saeedi [61] observed sensitivity of oil recovery to the level of heterogeneity and fluid chan nelling through high permeability layer is dominant with increasing permeability ratio between two layers. Alhamdan, Cinar [62] used a glass bead packs with layered porous media and demonstrated that the high flow capacity domain by the high permeability layer and its thickness always dominate displacement. Bahralolom, Bretz [63] ob served that the existence of a preferential flow path in visual etched glass models resulted in early breakthrough and increase in the CO_2 volume required to recover the in situ oil. Similarly, Al Wahaibi and Al Hadhrami [64] observed early CO_2 breakthrough and delayed recovery in heterogeneous bead packed models with permeabilities in the range of 1000 2500 mD. In another core scale experimental study, Fernø, Steinsbø [65] found the oil recovery in synthetic fractured core samples flooded with CO_2 to be dominated by fracture permeability. Khosravi, Bahramian [66] also found the miscible CO_2 injection to be capable of achieving a RF of around 80% in fractured core samples which is less than typical miscible CO_2 RF's ($\geq$ 90%) in homogeneous samples. In addition to experimental studies, Pande and Orr [53] presented the results of a study in which they used an analytical approach to calculate recovery of CO_2 flooding in a two layered system by changing the PR between the two layers. They reported on the positive effect of cross flow working against the negative effects of heterogeneity on recovery. Several numerical simulation studies have also shown the importance of core scale heterogeneity on multiphase fluid displacement [67,68]. All the previous studies, regardless of their nature and scale, have one point in common: they all agree that heterogeneity inevitably leads to early breakthrough and reduced recovery requiring a substantial in crease in the volume of injected fluids needed to recover the in situ oil.

As revealed by the above review of the existing literature, to date there have been limited efforts focused on evaluating the effects of heterogeneity on the recovery at the core scale using experiments conducted on real rock samples. Even less work has been done to un derstand such effects using a systematic approach of introducing het erogeneity into the experimental setup in a controlled manner. Furthermore, out of the existing few studies of this nature, none have focused on evaluating the effect of heterogeneity with WAG flooding or investigating the effects of crossflow and recovery mode (i.e. tertiary vs. secondary). In an attempt to bridge the identified gap in our knowledge, this study has used a controlled and reproducible approach to in vestigate and critically analyse the influence of permeability hetero geneity (PR) on the performance of miscible CO_2 WAG flooding. In doing so, the carefully designed experiments have also made it possible to explore and evaluate the effects of recovery mode (secondary vs. tertiary), heterogeneity direction (vertical vs. horizontal), degree of permeability heterogeneity (PR), and the presence or absence of crossflow on oil recovery.

2. Experimental methodology

2.1. Apparatus, chemicals and test conditions

A high pressure high temperature core flooding facility was built for the CO_2 WAG flooding experiments. The system consists of three major components: the injection system, the core holder assembly and the production system. These are connected together using a series of flow lines, fittings and valves (Fig. 1). The injection system itself included two syringe pumps (Teledyne Isco, Model 65D) used for fluid injections and two stainless steel transfer cylinders used for storing and injecting n C_{10} and CO_2. The core holder assembly included a hydrostatic biaxial type core holder (Core Laboratories, FCH Series) and at each end an absolute pressure transducers was attached (Omega Engineering, PX309 2KG5V) to record the inlet and outlet pressures of the core holder. A third syringe pump (Teledyne Isco, Model 65D) was used to control the confining pressure applied through the core holder to the core sample. On the production side, to provide a stable pressure reg ulation during the flooding process, a high precision dome loaded backpressure regulator (BPR) (Equillibar, U10 L Series Precision BPR) was used in combination with an N_2 gas cylinder to provide the set pressure for the BPR. Finally, with the production system, a fraction collector used to collect and record the amount of produced fluids during the course of the flooding experiment.

Injection fluids included $n\,C_{10}$ (99 mol%, Sigma Aldrich), high purity CO_2 (99.9 wt%, BOC Gases) and synthetic brine. The synthetic formation brine was prepared by dissolving analytical grade salts (Sigma Aldrich) in distilled water at concentrations of 20 g NaCl, 7 g KCl and 5 g $CaCl_2.2H_2O$ per litre of solution. The density and viscosity of $n\,C_{10}$ and CO_2 are 707.7 Kg/m^3, 0.591 C.p. and 590 Kg/m^3, and 0.045 C.p., respectively, at our experimental condition. The experi ments were conducted at the confining pressure, pore pressure and temperature of 34.46 MPa, 17.23 MPa and 343 K, respectively. The pore pressure was chosen to be above the MMP (minimum miscibility pressure) of $CO_2/n\,C_{10}$, so that in the experiments, CO_2 would be first contact miscible with $n\,C_{10}$. An MMP of 12.6 MPa for $CO_2/n\,C_{10}$ at 344 K is reported in the literature [69,70].

2.2. Core sample preparation

Three sets of homogeneous cylindrical core plugs all with 76.5 mm length and 38.1 mm diameter were obtained from quarried sandstone blocks in the U.S. (Table 1). These core plugs were used to manufacture samples with controlled axial and radial (i.e. composite and layered) heterogeneity arrangements by cutting and assembling the pieces in different ways (Fig. 2). For example, a layered sample with radial (or vertical) heterogeneity was achieved by cutting two core plugs (each with a different permeability) axially into two halves and then con structing a heterogeneous plug by placing one half from each plug in parallel to make up a full diameter plug (Fig. 2(b)). Using this approach, three different levels of heterogeneity were achieved by changing the permeability ratio (PR) between the two halves (Table 1). Furthermore, the effect of crossflow between the two half cores on the experimental results was evaluated by placing either an impermeable thin (1 mm) Teflon sheet or a permeable lint free tissue paper between the two halves of the layered sample assemblies. The lint free tissue paper was used to help with establishing capillary continuity as well as promoting crossflow. Composite samples with axially heterogeneity were con structed by cutting homogeneous samples into approximately 35 mm long segments and then stacking segments of different permeability values in series one after another (Fig. 2(c)). The lint free tissue paper was again inserted in between the polished joints of the core segments of the composite core to aid in establishing capillary continuity. It is worth noting that the 17.23 MPa net effective stress (confining pressure minus pore pressure) applied to the samples was expected to help in achieving a very close match between the layers or segments of the heterogamous samples.

2.3. Experimental procedure

The homogeneous core plugs were cleaned in a temperature con trolled Dean Stark apparatus using warm methanol and toluene and

Table 1
Basic characteristics of the homogeneous and heterogeneous layered samples.

Heterogeneity level	Lithology	Nominal porosity (%)	Nominal permeability (mD)	PR
Homogeneous	Grey Berea	18	100	1
Weak	Bandera	19	20	2.5
	Kirby sandstone	23	8	
Moderate	Grey Berea	18	100	5
	Bandera	19	20	
Strong	Grey Berea	18	100	12.5
	Kirby sandstone	23	8	

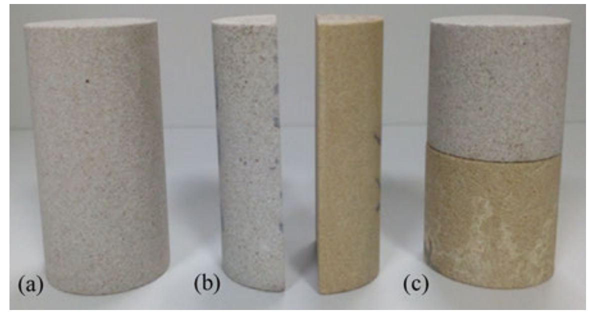

Fig. 2. Different samples configurations used (a) a homogeneous core plug, (b) a heterogeneous layered sample, (c) a heterogeneous composite sample.

then dried in a vented oven at 343 K for 24 h or until their weights stabilised. Then their porosity and absolute permeability were mea sured using an automated helium porosi permeameter before under going the flooding procedure. The core flooding procedure used here is designed based on the procedures and protocols available in the pub lished literature [7,71]. First of all, a homogeneous or manufactured core (Table 1) was wrapped with a multilayered sleeve to protect the integrity of the core holder assembly during the flooding process [7]. After loading the wrapped sample into the core holder, a low confining pressure (5 MPa) was applied to the sample and the sample was put under vacuum for 12 h. Synthetic formation brine was then injected into the sample to increase the pore pressure while the confining pressure raised accordingly maintaining a net effective stress of 17.23 MPa at all times. Meanwhile the experimental temperature was increased and maintained at the predefined value as specified earlier. The system was left under test conditions for 6 h to develop pressure and temperature stability throughout the system in addition to achieving a full brine saturation and establishment of adsorption equilibrium in the brine saturated sample. The brine permeability of the sample was then measured by injecting the formation brine at a con stant flow rate.

Approximately, five pore volumes (PV) of $n\,C_{10}$ were injected through the sample at 5 mL/min to achieve the irreducible water sa turation (S_{wr}). It is worth noting that this relatively high injection rate of $n\,C_{10}$ was to impose adequate differential pressure across the samples to help with achieving a more effective displacement of brine by $n\,C_{10}$. We addressed the concern about decane sweep efficiency in displacing the brine in low permeability layer in previous publication [60] using an X Ray computed tomography (XCT) scanner. The results confirmed that decane adequately displaced the brine in both layers. In the next step, depending on the EOR mode investigated, either WAG (secondary mode) or brine (tertiary mode) was injected through the core sample. In experiments focused on the tertiary mode EOR, 4 6 PV s of brine were injected at 4 mL/min through the plug to establish residual $n\,C_{10}$ sa turation. While, in experiments investigating the secondary mode EOR, the previous step was skipped. Subsequently, alternating slugs of CO_2 and water were injected at a flow rate of 1 mL/min with (Water flow rate determined according to the following equation reported by Ra poport and Leas [72] $L\mu V \geq 1$ 5. While CO_2 injection rate was de termined according to Zhou, Fayers [73]) a slug size of 0.15 PV and a WAG ratio of 1:1. Throughout this procedure, the volume of $n\,C_{10}$ collected at the production side of the setup was recorded. The flooding was continued until 3.5 4 PV s of WAG were injected at which point no further appreciable $n\,C_{10}$ would be recovered.

3. Results and discussion

To explore the role of layered heterogeneity, four core flooding experiments with differing PR's were conducted and the oil recovery profiles were measured. In these four experiments, a lint free tissue paper was placed between the half plugs to promote crossflow. To

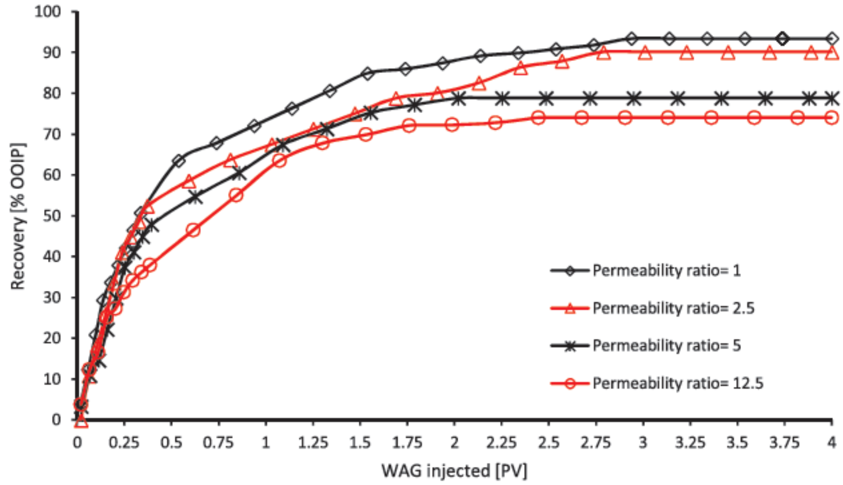

Fig. 3. A comparison between recovery profiles for layered samples with different heterogeneity levels with crossflow.

explore the role of crossflow on the oil recovery profile, four more experiments were conducted with the insertion of an impermeable Teflon sheet between the half plugs to prevent crossflow. These WAG core flooding experiments are conducted under secondary EOR mode. A comparison study between the performance of WAG flood under secondary and tertiary modes whose results was also conducted.

3.1. Influence of layered heterogeneity

As outlined earlier, PR values of 1.0, 2.5, 5 and 12.5 were utilized with a value of 1.0 representing a homogeneous sample and values of 2.5, 5 and 12.5 representing weak, moderate and strong heterogeneity levels, respectively. Fig. 3 illustrates the recorded recovery versus the number of PVs of WAG injected for the above mentioned experiments, each curve representing a particular PR value. From these measurements, as expected, the ultimate recovery from the homogeneous core (PR = 1.0) is the highest (93.4%). The main reason for this observation is that the WAG front moves more evenly in this sample and fluid distributions in the flooded part of the sample are expected to remain spatially more homogeneous even after breakthrough resulting in a more sustained higher recovery rate. For the other three heterogeneous samples, the recovery profile before breakthrough (BT) is to some extent similar to that of the homogeneous sample, however, the BT occurs earlier as the PR increases (Table 2) and after BT they tend to flatten out earlier resulting in lower recoveries at the end of displacement process (Fig. 3). As can be seen from Table 2, increasing the PR values from 2.5 to 5 and then 12.5, the RF at BT decreases from 48.6% to 44.8% and then to 37.3% and, similarly, the ultimate RF decreases from 90.1% to 78.8% and then to 74.0%. The trend observed between the ultimate RF and PR is consistent with that reported previously for CO_2 floods by other researchers [22,53,57]. In the heterogeneous samples, the injected fluids tend to flow preferentially through the high permeability layer bypassing the low permeability layer. It is worth noting that the RF's achieved here for the heterogeneous samples is with the aid of WAG that, as a means of profile control, is expected to have lowered the effective mobility of CO_2 in the high permeability layer, thus diverting it into the low permeability one. In fact, for every heterogeneity case, the RF achieved using WAG is sufficiently higher than that obtained with continuous CO_2 flooding as reported in our previous research work [60,61].

As another observation, it can be seen from Fig. 3 and Table 2 that doubling of PR from 2.5 to 5 results in about 11.3% decrease in the ultimate recovery while increase in PR from 5 to 12.5 (a further 2.5 times increase) causes only about 4.8% decrease in the RF. This demonstrates that with continued increases in PR the effect of heterogeneity on the ultimate RF tends to diminish. The primary cause of such an observation is the diminishing contribution of the low permeability layer to the total recovery. Pande and Orr [53] have observed a similar trend among the RF's by varying PR in the range of 1.0 10.0. Zhao, Hao [57] have also reported a mere 9.0% decrease in the ultimate recovery by increasing the PR from 10 to 100.

It is worth noting that some of the above reported flooding experiments were repeated to examine the reproducibility of the results. Although the RF values of the repeat runs shifted by an average increment of ± 1.0%, which may be considered within the experimental error, the overall trends discussed above remained unchanged.

3.2. Influence of crossflow on recovery

We conducted six experiments with the objective of achieving a better understanding of the effect of crossflow on recovery under a range of different PR values (i.e. 2.5, 5 and 12.5). In the first set of three experiments, a lint free tissue paper was placed between the two halves of the layered samples to promote crossflow (i.e. fully communicating layers). For the second set, a thin (1 mm thick) Teflon sheet was inserted between the two halves to prevent crossflow (i.e. non communicating layers). Since the high permeability half plug was placed on top in all the layered samples tested in this study, gravitational forces may have only minor contribution to the diversion of CO_2 to the high permeability layer, something which would be eliminated altogether in the case of non communicating layers. It is also worth noting that all six experiments whose results are discussed in this section were conducted using a secondary mode EOR flooding scheme.

Fig. 4 presents the ultimate recoveries achieved for every PR with

Table 2
Ultimate recoveries and breakthrough properties for rock samples with different heterogeneity levels with crossflow.

PR	Heterogeneity level	S_{oi} (1-S_{wc}) (%)	PV's injected at breakthrough	RF (%) at breakthrough	S_{or} (%)	Ultimate RF (%)
1	Homogeneous	78	0.317	48.6	6	93.4
2.5	Weak	75	0.283	44.8	8	90.1
5	Moderate	73	0.253	37.3	16	78.8
12.5	Strong	73	0.203	27.2	19	74.0

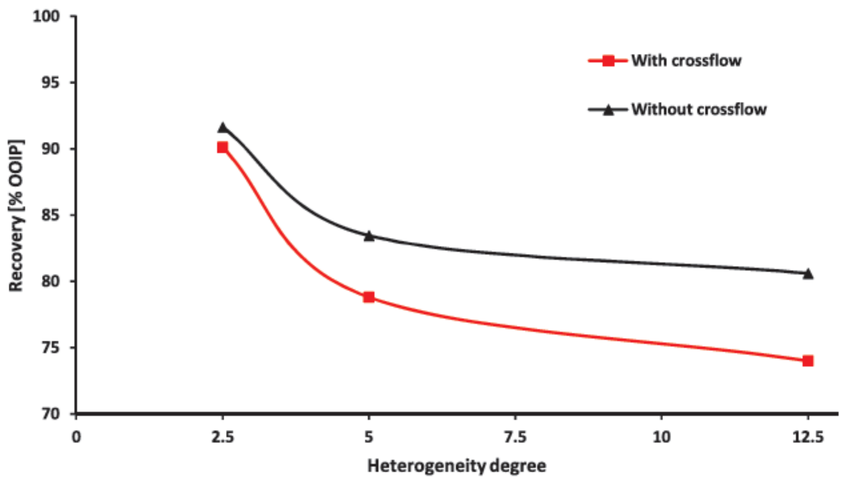

Fig. 4. A comparison between the ultimate oil recoveries in heterogeneous core samples with and without crossflow.

and without the crossflow. As can be seen, similar to the results reported in the previous section for the experiments with crossflow, in the case of non communicating layers the RF decreases as the PR increases. However, a comparison between the two cases (i.e. communicating and non communicating) reveals that crossflow seems to decrease the RF across all PR values and such an effect (i.e. the separation between the two curves in Fig. 4) becomes more pronounced as the PR increases. In other words, crossflow conforms to the worsening negative effect of channelling in layered systems resulting in further deterioration of oil recovery as the PR increases. The above trend is opposite to that previously reported in the literature for the case of continuous CO_2 flooding where crossflow enhances oil recovery [53,55,61,74].

This difference can be attributed to the driving mechanisms behind the oil recovery under WAG flooding. It is believed that during WAG flooding in a non communicating layered sample the viscous forces become more dominant resulting in better conformance control. This argument finds support in Fig. 5 which shows the recorded differential pressure across a layered core sample versus time for both scenarios of with and without crossflow. As can be seen, on average, higher differential pressures (i.e. more pronounced viscous forces) were induced during the WAG flooding under the non communicating scenario. The domination of viscous forces can suppress the capillary forces resulting in better mobilisation of the in situ oil. The higher differential pressure in the case of non communicating layers may be attributed to the fact that, in the absence of crossflow, any CO_2 delivered to the low permeability layer would be forced to flow in this layer. The first WAG slug (i.e. 0.15 PV of CO_2) injected at the start of the WAG flood tends to flow preferentially through the high permeability layer mostly bypassing the low permeability one. However, as expected from a WAG flood, the subsequent water slug would lower the effective mobility of the flood diverting more of the succeeding CO_2 slugs to the lower permeability layer [52]. For the non communicating case, any CO_2 penetrating the low permeability layer would be forced to stay and continue advancing there since there is no communication between the two layers leading to higher oil recoveries compared with the case of fully communicating layers where any CO_2 initially delivered to the low permeability layer may be diverted back into the high permeability layer as the preferred flow path.

3.3. Influence of composite heterogeneity

Langaas, Ekrann [75] suggested that, for a composite sample, individual plugs need to be arranged with decreasing permeability in the flow direction to promote a more uniform displacement and achieve a low residual saturation. However, this conclusion is more applicable to immiscible displacement where capillary forces are appreciable. Shedid [56] experimentally evaluated the effect of permeability sequence in composite cores made up of three plugs with low (L), medium (M) and

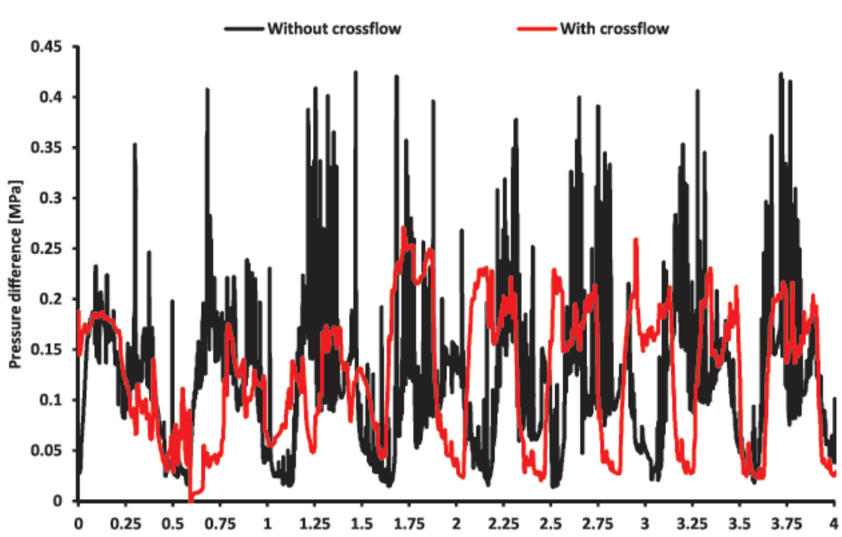

Fig. 5. Measured differential pressure between the inlet and outlet of a layered core sample with and without crossflow versus WAG injection pore volume.

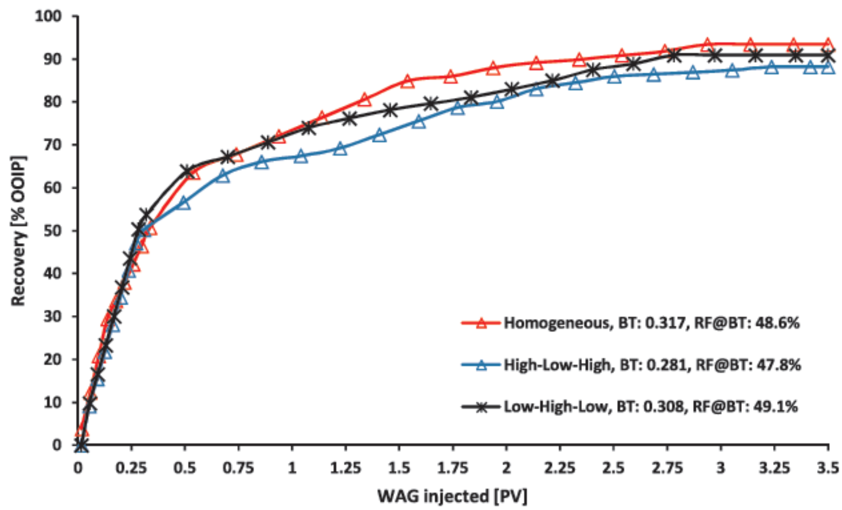

Fig. 6. Effect of composite heterogeneity sequence on the recovery profiles.

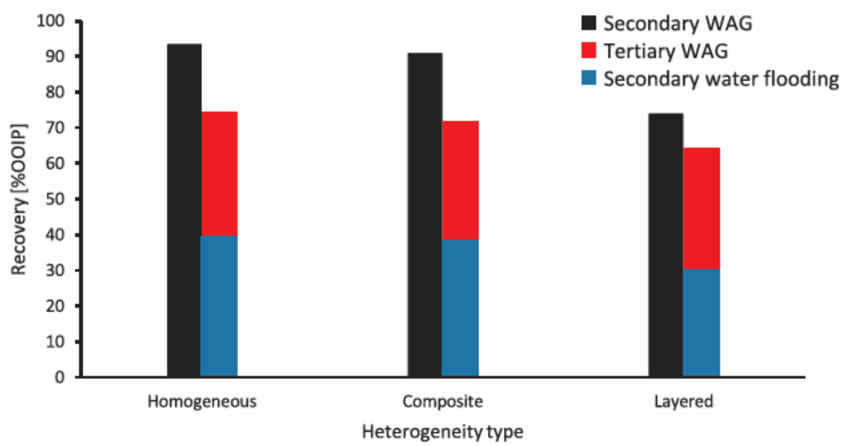

Fig. 7. Effect of injection mode on ultimate oil recovery factors for different types of heterogeneities.

high (H) permeabilities on the ultimate recovery during miscible CO_2 flooding. In his study, the permeability sequences of medium low high (MLH) and medium high low (MHL) along the flow direction yielded recoveries of 91.0% and 81.5%, respectively, which were the highest among all the sequences examined.

We performed three experiments investigating the effect of perme ability sequence in the direction of flow on the ultimate recovery of miscible WAG flooding in composite samples. In addition to a homo genous plug, we tested two composite samples each of which included three individual plug segments with either low (L) or high (H) perme ability values (i.e. 8 mD, 100 mD, respectively). Fig. 6 presents the oil recovery versus PVs of WAG injected for all three samples. As can be seen, all recovery profiles seems to match closely before BT, however, as the experiment proceeds during the post BT, the effect of hetero geneity and permeability sequence start to differentiate resulting in the highest RF for the homogeneous (93.4%) followed by 90.9% and 88.2% for the L H L and H L H sequences, respectively. The higher RF of the L H L sequence compared with H L H may be attributed to the placement of a low permeability plug at the outlet of the sample that would result in a more uniform and conformed displacement in this sample com pared with the H L H sequence. Lastly, the effect of composite hetero geneity on the ultimate recovery is much more subtle than that of the layered heterogeneity as there is no opportunity for preferential chan nelling of the injected fluids in the composite samples. Furthermore, under miscible flooding conditions, capillary forces play no role in in fluencing the outcome. This absence of capillary forces is expected to considerably reduce the effect of axial permeability arrangement on ultimate recovery. In addition, it is believed that the small diameter of the core segments included in the composite cores has also suppressed the possible effects of differing axial arrangements. In other words, the ultimate recoveries for various arrangements might have been different if larger diameter samples were used as that would make the floods to possibly deviate from a single dimension displacement type. It is worth noting that all three experiments whose results are discussed in this section were conducted using a secondary mode EOR flooding scheme.

3.4. *Influence of EOR mode (Secondary vs. Tertiary)*

We conducted six experiments (two pairs of each three experiments) to evaluate the influence of flooding mode (secondary vs. tertiary) on ultimate oil recovery. The experiments covered different heterogeneity levels/configurations including homogeneous, layered (PR = 12.5) with crossflow and composite (low high low: 8 100 8 mD). In all cases, as depicted in Fig. 7, the secondary recovery mode resulted in higher RF compared with the tertiary recovery mode. Similar results have been reported in the literature [23,76], for instance, a recovery of 91.0% is observed when conducting WAG under secondary mode compared to only 55.0% under the tertiary mode for homogeneous systems [41]. Almehaideb, Shedid [77] have also shown that an earlier miscible CO_2 injection during the recovery results in a higher ultimate oil recovery. Higher recovery resulting from the secondary recovery mode can be attributed to the less pronounced effect of water shielding which im pedes the access of the injected CO_2 to the residual oil in the case of tertiary recovery mode [6,76,78 80]. In other words, the secondary mode injection facilitates the contact and miscibility between the oil and the injected CO_2 leading to higher recoveries.

Another observation from Fig. 7 is that under both secondary and tertiary modes, as may be expected, the highest recoveries was achieved for the homogeneous sample. Also among the two types of hetero geneous samples examined, the composite sample yielded a higher re covery. Lower recovery from the layered sample can be attributed to the injection fluid channelling through the high permeability layer and the bypass of decane in the low permeability layer, something that does not take place in the composite sample.

4. Conclusions

The effect of core scale heterogeneity on the performance of mis cible CO_2 Water alternating gas (WAG) flooding was evaluated sys tematically using a series of manufactured heterogeneous core samples tested under various flood conditions. The results indicate that in the layered samples the level of heterogeneity (PR) strongly affects the recovery with higher PR resulting in lower ultimate RF. In the com posite samples also the permeability sequence along a sample's length has a noticeable influence on ultimate oil recovery. As an another outcome of this study, it was observed that the miscible WAG flooding performs better when injected under the secondary recovery mode where the miscibility is enhanced by facilitating more effective contact between CO_2 and the in situ oil. Evaluation the effect of crossflow in layered samples revealed that displacement in non communicating experiments would result in higher recoveries. These higher recoveries in the absence of crossflow may be attributed to higher dominance of viscous forces as revealed by the measurement of the pressure drop data. Moreover, this effect tends to become more pronounced as the PR of the layered samples increases.

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Chapter 7

7.1 Summary, Conclusions and Recommendations

7.1.1 Summary

Carbon dioxide (CO_2) flooding is a promising enhanced oil recovery (EOR) technique as demonstrated by various experimental and numerical simulation studies and field-scale applications. In addition, CO_2 enhanced oil recovery (CO_2-EOR) presents a real potential in mitigating the global warming phenomenon by sequestering the unwanted gas permanently in oil reservoirs once flooded. However, the same evidence pointing to its great potential has also revealed that in general CO_2-EOR tends to suffer from a number of inherent technical deficiencies associated with the unstable nature of the displacement of the reservoir oil. The flood instabilities are mostly attributed to the high mobility of the injected CO_2 resulting in viscous fingering and therefore non-uniform displacement of the oil. Depending on the in-situ conditions, the relatively lower density of CO_2 compared with that of the oil can also play a role by causing gravity override. Although the above unfavourable phenomena are expected to take place even in a homogenous rock formation, for the viscous instabilities in particular, their negative effects on the outcome of a CO_2-EOR process would become much more pronounced in the presence of reservoir heterogeneity. Therefore, given the heterogeneous nature of hydrocarbon reservoirs, for better technical and economic evaluation of this EOR technique a detailed fundamental understanding of how, at least, basic reservoir heterogeneity configurations (i.e. layering) may influence the displacement process is needed.

Given the scarcity of existing relevant data and information, the main objective of the current research has been to provide a deeper quantitative and qualitative experimental understanding of the effects of a number of critical factors on the performance of CO_2-EOR in heterogeneous core samples. The heterogeneity configurations investigated included composite (i.e. change in permeability in the direction of the flood) and layered (i.e. change in permeability perpendicular to the direction of the flood). The specific factors whose effects were investigated included the permeability ratio (PR) and crossflow between the layers included in layered samples, permeability sequence in composite samples, EOR flooding scheme (e.g. continuous CO_2 injection vs. WAG flood), EOR flooding mode (i.e. tertiary vs. secondary injection) and the miscibility conditions. Thus, core flooding experiments were conducted under elevated pressures (either 9.6 MPa or 17.2 MPa) and a fixed temperature of 343K. The two pressures used would enable performing the experiments under both immiscible and miscible flooding conditions. The heterogeneous samples were carefully manufactured using originally homogenous cores and the interlayer communication for layered samples was controlled by either the insertion of an impermeable Teflon sheet or a water-wet permeable tissue paper in-between their two layers. The originally homogenous cores were categorised into three groups according to their original nominal permeability which was either 8mD (relativity low permeability (L)), 20mD or 100mD (relatively high permeability (H)). The PR values examined included 1.0, 2.5, 5 and 12.5 with a value of 1.0 indicating a homogeneous sample and values of 2.5, 5 and 12.5 representing weak, moderate and strong heterogeneity levels, respectively. The composite arrangements explored included H:L, L:H:L, L:H, and H:L:H. For example, a L:H:L arrangement would mean placing a 100mD core segment in between two other segments each with a permeability of 8mD. To achieve a better understanding of fluid distributions and explain some of the suspect mechanisms behind the oil recoveries obtained under various flooding configurations, two of the core flooding experiments were imaged in real-time using an X-ray computed tomography (X-ray CT) scanner.

7.1.2 Conclusions

The main conclusions drawn from the interpretation and discussions presented in each of the published work included in this dissertation are summarised below.

7.1.2.1 Influence of permeability heterogeneity on miscible CO_2 displacement efficiency

The permeability ratio (PR) in layered samples was found to strongly affect the recovery with higher PR resulting in lower recovery factor (RF). For example, the ultimate oil recovery decreased by 18.0% (from 87.8% to 69.8%) with changing the PR from 2.5 to 12.5. In the composite samples manufactured using either two or three individual plugs with relatively low (L: 8 mD) or high (H: 100 mD) permeability values the permeability sequence along the sample length was found to influence the recovery during intermediate injection times. For example, at 0.8 PV of CO_2 injected, for the H:L, L:H:L, L:H, and H:L:H composite sequences the oil recovery was calculated to be 69, 65, 78, and 73%, respectively. These recovery figures indicate that during intermediate flooding times, a sample with a high permeability plug placed at its outlet would give a better recovery. This behaviour was attributed to the fact that in samples with low permeability plug placed at their inlet a larger differential pressure is imposed by this plug and initially the injected CO_2 becomes more compressed as it begins to penetrate the sample. Once CO_2 passes through the low permeability plug and reaches the high permeability one, it becomes decompressed displacing oil out of the sample with a higher rate. However, during longer flooding times, all composite arrangements were found to result in similar RF's. This was believed to be a result of not having a preferential flow path along the length of these samples.

The experiments also revealed that the miscible CO_2 flooding would perform better when injected under the secondary recovery mode where the miscibility is enhanced by facilitating more effective contact between CO_2 and the in-situ oil. For example, under PR=5 the secondary flooding mode resulted in 77.9% of recovery compared with an RF of 71.5% obtained from the tertiary mode. This suggests that the presence of high water saturation under tertiary mode would give rise to the water shielding effect which impedes the access of the injected CO_2 to the oil phase. The experiments evaluating the effect of crossflow in layered samples revealed that, for the case of continuous CO_2 injection, the occurrence of crossflow improves recovery by moving oil from the low permeability layer into the high permeability one as well as reducing the CO_2 mobility in the high permeability region by promoting two-phase flow. For instance, increment oil recoveries of 4.8%, 4.5% and 1.8% were achieved by crossflow for the PR's of 2.5 to 5 then 12.5, respectively. These results also suggested that the positive contribution of crossflow to recovery factor tends to diminish as the PR increases because in such a case the dominance of gas channelling on the displacement process would become stronger.

7.1.2.2 Influence of permeability heterogeneity on immiscible CO_2 displacement efficiency

For the immiscible CO_2 flooding, similar to the miscible case the layered heterogeneity was found to negatively impact on the recovery profiles with the higher the PR the lower the ultimate RF. For instance, RF's of 72.1, 69.9 and 54.7% were recorded for PR's of 2.5, 5 and 12.5, respectively. In fact, the immiscible flooding tests imaged with the aid of an X-ray CT scanner confirmed the strong control of core-scale heterogeneity on the displacement performance and spatial distribution of CO_2. The channelling of CO_2 through the high permeability layer leaving a considerable amount of oil untouched in the low permeability layer was visually demonstrated. As expected, the RF achieved with every PR under immiscible conditions was considerably less than that obtained for the same PR under miscible conditions. In addition, the experimental results indicated that in immiscible flooding the permeability sequence along the length of the composite samples would influence the ultimate recovery appreciably. This observation is opposite to the conclusion made about the miscible flooding case for which the permeability sequence had a negligible influence on the ultimate RF. This difference is attributed to the influence of capillarity during immiscible displacement as capillary forces are active in an immiscible flood due to the appreciable interfacial tension (IFT) between the fluid phases.

The experiments evaluating the effect of crossflow in the layered samples revealed that the crossflow has an appreciable potential to enhance recovery as it resulted in the incremental of oil recoveries of 4.6, 2.3 and 4.7% for PR's of 2.5, 5 and 12.5, respectively. Besides, the application of X-ray imaging presented new evidence towards the potential impact of crossflow on in-situ fluid distribution and the recovery process. These experiments resulted from visual evidence confirming that crossflow has a reasonable potential to enhance recovery, but its effect is counteracted by significant channelling of CO_2 through the high permeability layer that reduces the amount of incremental oil mobilised by crossflow. A detailed inspection of the X-ray images also indicated that the CO_2 entering the low permeability layer due to crossflow would become trapped as a discontinuous phase along the length of the sample.

7.1.2.3 Influence of permeability heterogeneity on miscible CO_2 Water Alternating Gas (WAG) displacement efficiency

Similar to the case of continuous CO_2 flooding, the performance of miscible CO_2 Water alternating gas (WAG) flooding in the layered samples was found to be strongly controlled by the level of heterogeneity (PR) with higher PR resulting in lower ultimate RF. For instance, with increasing the PR values from 2.5 to 5 and then 12.5, the ultimate RF decreased from 90.1% to 78.8% and then to 74.0%. However, the RF's obtained using the WAG flooding scheme, as a means of profile control, were sufficiently higher than those obtained with continuous miscible CO_2 flooding. Moreover, the performance of WAG flooding was found to improve when conducted under the secondary recovery mode where the miscibility would be enhanced by more effective contact between injected CO_2 and the in-situ oil. For example, RF's of 93.4, 90.9 and 74% were obtained under secondary mode compared to 74.2, 71.3 and 74% resulted under tertiary mode for homogeneous, composite and layered samples, respectively. Unlike the case of continuous CO_2 flooding, the absence of crossflow under WAG flooding in layered samples resulted in higher recoveries. Such an effect could be attributed to higher dominance of viscous forces when no communication was allowed to take place between sample layers. The improved role of viscous forces was demonstrated by the higher differential pressures recorded across a sample when crossflow was not allowed. The significance of this effect was found to become more pronounced as the PR of the layered samples increased. For the composite samples, the influence of permeability sequence along a sample's length was found to have a subtle influence on ultimate oil recovery. For instance, the RF's of 93.4, 90.9 and 88.2% were recorded for the homogeneous, L-H-L and H-L-H sequences, respectively.

7.3 Recommendations

Any further research in the area explored by this research work may benefit from the following recommendations:

- Conducting pore-scale experimental work to investigate the role of different mechanisms (e.g. gravity, capillary and viscous driving forces) which may provide further insights into how various mechanisms may contribute under different flooding schemes/mode.

- Investigating the influence of wettability state on the performance of flooding mode in layered porous media.

- Conducting numerical simulation studies at various scales (e.g. pore-, core- and field-scale). These studies can lead to a better understanding of the influence of different displacement mechanisms under various scales.

- For WAG flooding scheme, a slug size of 0.15 PV was used to conduct experiments, this value recommended for homogeneous porous media. Therefore, conducting core flooding experiments using a heterogeneous sample to optimize slug size is highly recommended.

- X-Ray CT scanner was used during experiments, which may be difficult to interpret when it comes to some important phenomena which may happen at the rock/fluid interface. Thus, a micro-CT scanner is recommended to perform such analysis.

- In this study, perfectly horizontal and vertical heterogeneities were used to investigate the role of heterogeneity on multiphase flow. However, heterogeneity may be present at other in-between angles, thus, it is highly recommended to investigate the effect of such heterogeneity arrangements.

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Appendices B: Attribution of Co-Authors

Paper title: "**Influence of permeability heterogeneity on miscible CO_2 flooding efficiency in sandstone reservoirs- An experimental investigation**", Transport in Porous Media, 2018.

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Paper title: "**Insight Investigation of Miscible $_{SC}CO_2$ Water Alternating Gas (WAG) Injection Performance in Heterogeneous Sandstone Reservoirs**", Journal of CO_2 Utilization, 2018.

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