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MEMORY

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-THEME-

Overview of impact of the CO2 injection as EOR+ mode on the natural fractured reservoir to improve the ultimate oil recovery factor

Defended on: 07/06/2023

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Acknowledgments

Now is the time to put an end to this manuscript and these years of 2023.

We would like to thank my supervisor, ***DR. DJEBBAS. Faycal*** *and* ***Mr. KHELIFA*** *for their consistent support and guidance while running this project. Furthermore, I would like to thank everyone who helped us, even with a word.*

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Thanks again to all….

Dedication

I dedicate this modest work:

To the most precious persons to my heart, to the crowns of my head, to the ones whose prayers were accompanying me day and night to the ones who were sending me their whole hearted support to the ones who are always proud of me,

To my dear parents, for all their sacrifices, love, tenderness, support and prayers throughout my studies,

To my dear sisters for their constant encouragement and moral support,

To my dear brothers, for their support and encouragement,

To all my family for their support throughout my university career,

To my dear AIESERers, for their support and for being there for me,

May this work fulfill your longed-for wishes and the leak of your unfailing support,

Thank you for always being there for me.

Kaouther

Dedication

I dedicate the fruits of this work to:

Praise is to Allah, who has guided me in preparing this memorandum. I dedicate this to those whom I hold in higher regard than myself, to those who sacrificed for me, and to those whose prayers never leave me.

I dedicate this to the great man, to the source of my strength, and to the one I strive to be as great as - my dear father.

To my paradise on Earth, to the lifelong companion, and to the strong woman - my beloved mother.

I dedicate this to my dear siblings who hold a special place in my heart, and whom I am grateful for their support and encouragement throughout my academic journey.

Dedicate this to my dear friends with whom I have created the most beautiful memories.

Dedicate this to those who wished to see me as a graduate today, to my dear grandfather whom God has granted healing, and to the souls of my ancestors, may God have mercy on them.

Ibtihal

Abstract:

Naturally fractured reservoirs (NFR’s) have great importance and differ from conventional reservoirs as these contain fractures throughout the reservoir and on which around 40% of the world’s reserves reside in these reservoirs. These reservoirs are dual porous media (facture network and matrix), usually with low matrix and high fracture permeability. This makes the selection of the appropriate EOR to improve the ultimate oil recovery factor in these reservoirs challenging.

Our project aims to investigate the efficiency of injecting CO2 gas as an EOR mode on improving the ultimate oil recovery factor and analyzing the effect of the key parameter of the reservoir and fluid properties on the CO2-EOR performance in the NFR.

Keywords: naturally fractured reservoir, CO2 injection, ultimate oil recovery factor, EOR mode.

Résumé:

Les réservoirs naturellement fracturés (RNFs) sont très importants et diffèrent des réservoirs conventionnels car ils contiennent des fractures dans l'ensemble du réservoir et environ 40 % des réserves mondiales se trouvent dans ces réservoirs. Ces réservoirs sont des milieux poreux doubles (réseau de fractures et matrice), dont la matrice est généralement faible et la perméabilité des fractures élevée. Il est donc difficile de choisir la méthode de récupération appropriée pour améliorer le facteur de récupération finale du pétrole dans ces réservoirs.

Notre projet vise à étudier l'efficacité de l'injection de gaz CO2 en tant que mode d’EOR pour améliorer le facteur de récupération ultime du pétrole et à analyser l'effet des paramètres clés du réservoir et des propriétés du fluide sur la performance de la CO2-EOR dans les réservoirs naturellement fracturés.

Mots clés : réservoir naturellement fracturé, injection de CO2, facteur ultime de récupération du pétrole, mode EOR.

الملخص:

الخزانات المكسورة بشكل طبيعي (NFR) لها أهمية كبيرة وتختلف عن الخزانات التقليدية لأنها تحتوي على كسور في جميع أنحاء الخزان والتي يوجد بها حوالي 40 ٪ من احتياطيات العالم في هذه الخزانات. هذه الخزانات عبارة عن وسائط مسامية مزدوجة (شبكة مقسمة ومصفوفة) ، عادةً ما تكون ذات مصفوفة منخفضة ونفاذية تكسير عالية. وهذا يجعل اختيار الاستخلاص المعزز للنفط المناسب لتحسين عامل الاسترداد النهائي للنفط في هذه الخزانات أمرًا صعبًا.

يهدف مشروعنا إلى التحقيق في كفاءة حقن غاز ثاني أكسيد الكربون كأسلوب الاستخلاص المعزز للنفط في تحسين عامل استرداد النفط النهائي وتحليل تأثير الخصائص الرئيسية للخزان وخصائص السوائل على أداء الاستخلاص المعزز للنفط بثاني أكسيد الكربون في هذه الخزانات.

<u>الكلمات المفتاحية</u>: الخزانات المكسورة بشكل طبيعي , حقن ثاني أكسيد الكربون, عامل الاسترداد النهائي للنفط,وضع الاستخراج المحسن للنفط.

Table of contents

Chapter III: Comparison study of different Enhanced Oil Recovery methods vs. CO2 injection applied on the Naturally Fractured Reservoirs

Chapter VI: CO2 injection on the Naturally Fractured Reservoirs

List of illustrations

List of tables

List of Abbreviations

CO2 :	Carbon dioxide
EOR :	Enhanced Oil Recovery
NFR:	Naturally Fractured Reservoir
WAG :	Water-alternating-gas
PV :	Pore volume
ASP :	Alkaline-Surfactant-Polymer
MMP :	Minimum miscibility Pressure
HCPV :	Hydrocarbon pore volume
EOS :	Equation of state
BPR :	Back pressure regulator
RF :	Recovery factor
HnP :	Huff and puff
HC :	Hydrocarbons
FCM:	First contact miscibility
MCM :	Multi contact miscibility
IM:	Immiscibility
OIPP:	Original oil in place
IFT:	Interfacial tension

List of symbols and units:

Φ_m:	Porosity of matrix
Φ_f:	Porosity of fracture
Φ_t:	Porosity total
K_m:	Matrix Permeability
K_f:	Fracture Permeability
V_m:	Total volume of matrix
V_f:	Total volume of fracture
C:	Compressibility
θ:	Contact Angle
σpp:	Interfacial tension
Sw:	Water saturation
S_{wi}:	Connate water saturation
S_{or}:	Residual oil saturation
N_w	Exponent for water
N_o	Exponent for oil
Cc:	Centimetre cubic
API:	American Petroleum Institute
Psi:	Pound per square inch
MPa:	Mega Pascal
Md:	Milidarcy

General Introduction

The Oil& Gas Production has been required for many years to meet the high energy demand worldwide. That leads countries to research new techniques to extract the trapped oil in the reservoir or exploit new potential reservoirs like the natural fractured reservoirs to improve production. That's why they use the EOR techniques to increase it.

Nowadays, new studies focus on the suitability of using the EOR techniques on natural fractured reservoirs to improve oil production.

The study problem: through the above, the following main problem can be raised:

The impact of CO_2 injection as EOR mode to improve the ultimate recovery factor on the natural fractured reservoir.

Sub-questions: From the main research problem, the following questions diversify:

1. Did the CO_2 method is the best choice for the EOR process in the naturally fractured reservoirs?
2. How will the characteristics of the naturally fractured reservoir affect the effectiveness of the CO_2 EOR process? (Heterogeneity, fracture properties...etc.)
3. Which injection mode is the most effective in improving the recovery factor?
4. Is the use of CO_2 EOR economically profitable?

Research methodology: to achieve the desired results and answer the main problem, in addition to the surrounding sub-questions, we relied on the descriptive, analytical and comparative approach, considering it the appropriate research method for this type of studies, collecting information and data, analyzing and studying a detailed scientific study.

Study objectives: The primary aim of this study is to generate a conclusion and recommendations based on the application of a data set constructed from CO_2 Injection-based studies and experiments. Specific objectives include:

- Understand the mechanism of CO_2 injection through the NFR.
- To know how the CO_2 injection mechanism behavior increases the recovery factor and to investigate the impact of the injection modes to improve it.
- To investigate the impact of the reservoir characterization on the performance of CO_2 injection.

Research method: To elaborate on the requirements of this problem, we divided this research as follows:

Chapter one: the naturally fractured reservoirs.

Chapter two: The key parameters affecting the selection of Enhanced Oil Recovery for the Naturally Fractured Reservoirs.

Chapter three: Comparison study of different Enhanced Oil Recovery methods VS CO_2 injection applied on the Naturally Fractured Reservoirs.

Chapter four: CO_2 injection on the Naturally Fractured Reservoirs.

Chapter I:

Naturally Fractured Reservoirs

1. **Introduction** :

With the development of oil and gas production and the increases in oil prices. The companies tried to increase their production and exploit new types of reservoirs, which are naturally fractured reservoirs. These reservoirs show great potential for oil and gas reserves, but extracting them from them is complex due to their heterogeneity.

2. **Naturally fractured reservoirs:**

Most oil and gas reservoirs worldwide are naturally fractured reservoirs.

The impact of the fractures' presence still needs to be fully understood, considering that they act as important thoroughfares for fluid flow.

2.1. **Definition:**

A natural macroscopic planar discontinuity in the rock caused by deformation or physical digenesis is known as a reservoir fracture. If it was due to brittle failure, it was likely initially open but could have subsequently changed or mineralized. If additional ductile failure was involved, it might be present as a band of severely deformed country rock. Natural reservoir fractures can influence fluid flow within the rock favorably or negatively.

This definition also enables studying fluid flow effects caused by different fracture morphologies. For instance, one can examine how highly permeable open fractures affect reservoir behavior. Still, they should also consider the significant anisotropy in rock permeability caused by low-permeability deformed fractures.

The notion of a "fractured reservoir" is considerably broader than the definition of a reservoir fracture. An operational description of a fractured reservoir is required because natural fracture systems can affect reservoir performance in primary, secondary, and tertiary recovery. These effects frequently must be predicted before they are shown in production data.

The definition "fractured reservoir" refers to a reservoir where naturally occurring fractures have, or are predicted to have, a significant impact on the flow of reservoir fluid, either through enhanced reservoir permeability and/or reserves or through high permeability anisotropy. Operationally, the qualifier is predicted to have a significant effect since it requires very early data collection to characterize a fractured reservoir. So, before accurate substantiation by production history, we frequently have to predict the "major effect" and treat the formation as a fractured reservoir.[1]

[1] : R.A. Nelson, BP Amoco, Houston, TX, Geologic Analysis of Naturally Fractured Reservoirs, Gulf Professional Publishing, p 15.

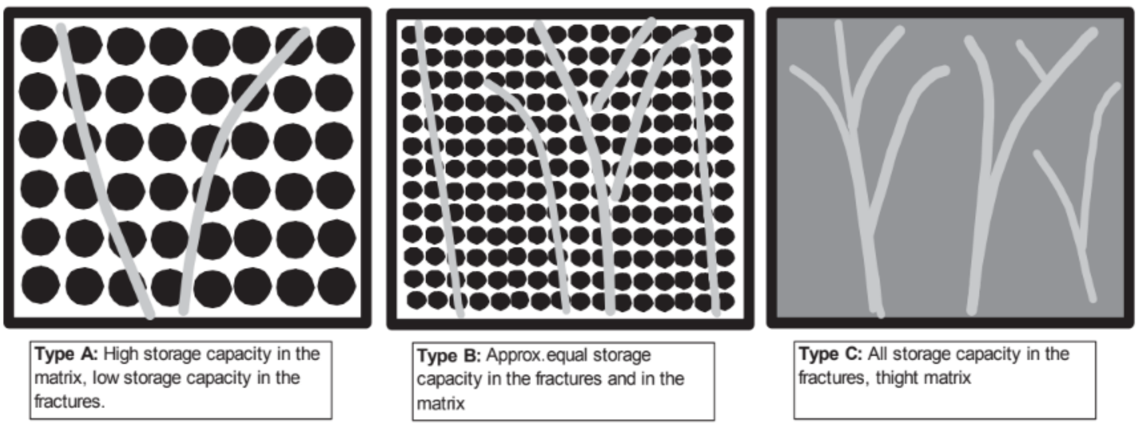
2.2. <u>Classification of the Natural Fractured Reservoirs:</u>

The naturally fractured reservoirs can be classified into different types depending on the storage capacities, porosity, and permeability of the matrix and the fractures. Different definitions for these types can be found in the literature. Aguilera classified the naturally fractured reservoirs into types A, B and C.

In reservoirs of type A, most fluid is stored in the matrix; the fractures provide only a very small storage capacity. [1]

Typically the matrix rock tends to have a low permeability, whereas the fractures exhibit a much larger permeability.

Approximately half of the hydrocarbon storage in type B reservoirs is in the matrix and half in the fractures. The fractures provide the storage capacity of type C reservoirs without the contribution of the matrix.



<u>Figure 1.1</u>: Porosity distribution in fractured rocks. (Zoltan E. HEINEMANN and Dr. Georg Mittermei, 2014)

Another classification of fractured reservoirs is given by Nelson, which is based on per cent of total porosity and permeability.

The parameters range in per cent due to matrix versus per cent due to fracture. In reservoirs of type I, fractures dominate porosity and permeability. In type II reservoirs, fractures control essential permeability; in type III reservoirs, fractures assist permeability. In reservoirs of type

[1] : Zoltan E. HEINEMANN, Natural fractured reservoir engineering, Professor Heinemann Doktorandengruppe, p 13.

IV, the fractures provide no additional porosity or permeability but can create anisotropic barriers.[1]

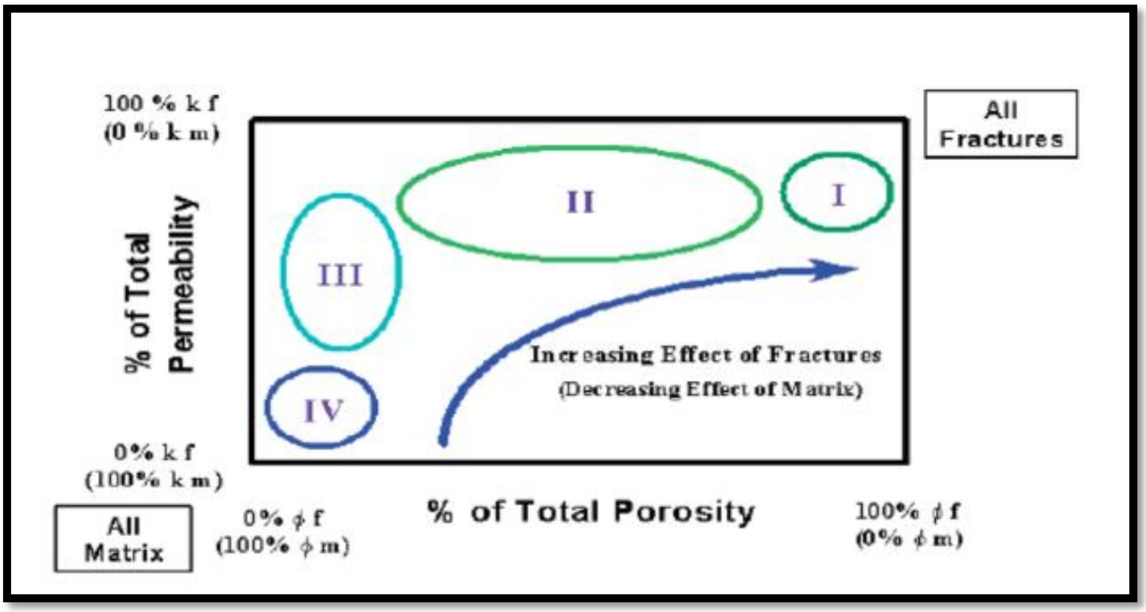


Figure 1.2: Classification of fractured reservoirs after Nelson. (Martin A. Fernø, 2012)

So, naturally fractured reservoirs are commonly geological formations characterized by a heterogeneous distribution of porosity and permeability. Based on the geological features related to hydrocarbon storage and the relationship between permeability and porosity, we indicate four types of fractured reservoirs:

Type I: little to no porosity and permeability in the matrix. The interconnected fracture network constitutes the hydrocarbon storage and controls the fluid flow to producing well.

Type II: low matrix porosity and permeability. Some of the hydrocarbons are stored in the matrix. Fractures control the fluid flow, and fracture intensity and distribution dictate production.

Type III: high matrix porosity and low matrix permeability. The majority of the hydrocarbons are stored in the matrix. Matrix provides storage capacity, and the fracture network transports hydrocarbons to producing wells.

Type IV: high matrix porosity and permeability. The effects of the fracture network are less significant on fluid flow. In this type category, reservoir fractures enhance permeability instead of dictating fluid flow.[2]

[1] : Previous reference, p 15.
[2] : Martin A. Fernø, Enhanced Oil Recovery in Fractured Reservoirs, in Tech publishing Croatia, p 2.

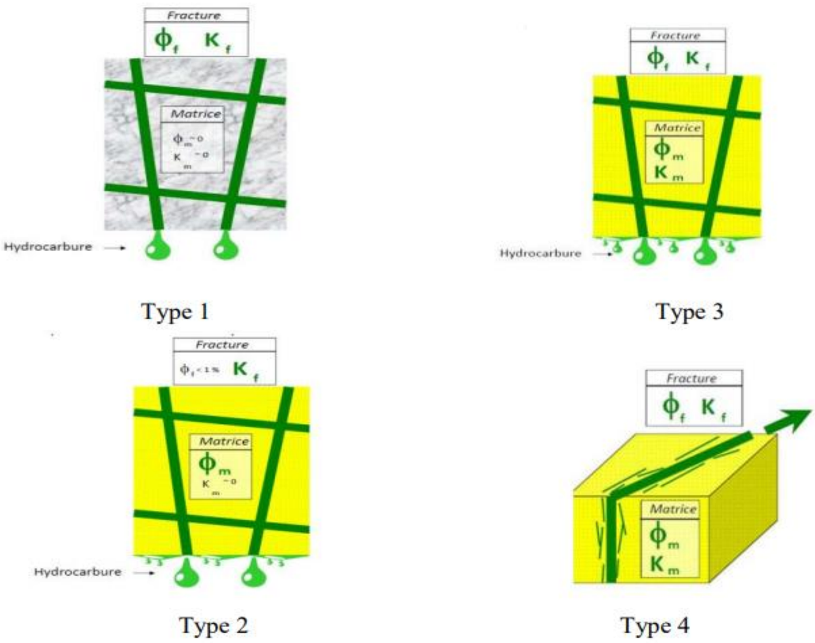


Figure 1.3: Porosity and Permeability distribution in Fractured Rocks. (Djebbar Tiab and Erle C. Donaldson, 2004)

3. The Naturally Fractured Reservoir Properties:

3.1. Reservoir properties :

a. Porosity and Double porosity :

Fractured reservoir rocks have two porosity systems: one inter-granular formed by void spaces between the rock grains and the other by fracture and vugs void spaces (figure 1.4). The first type of porosity is primary, found in sandstone or limestone. Secondary porosity or, when referring to only vugs or fractures, vugular porosity/fracture porosity is the second type. Secondary porosity is commonly found in compact, brittle rock with low inter-granular porosity, such as compact limestone, shale, shaly sandstones, siltstones, schist, etc.

Secondary porosity is typically caused by rock fracturing, jointing, and water dissolution.

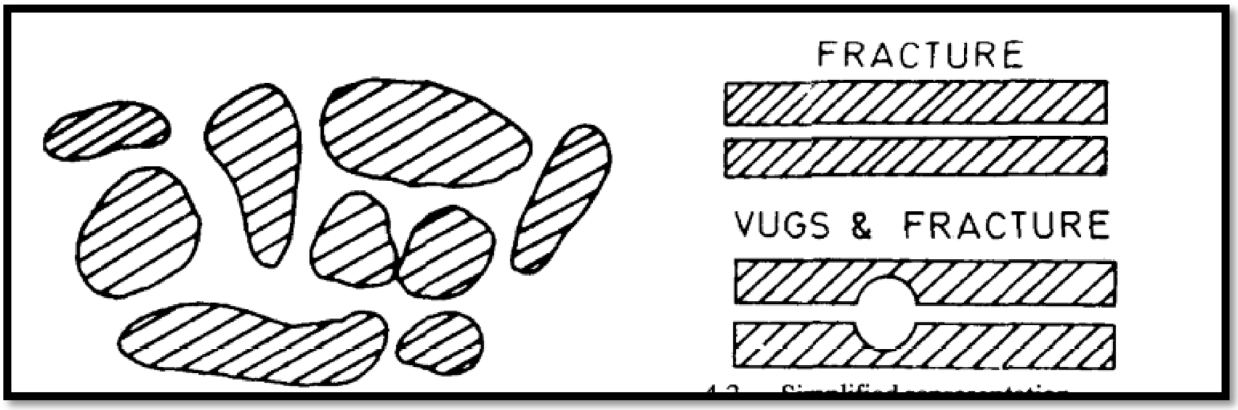


Figure 1.4: Consolidated grain void space (matrix) & Representation of vugs and fracture void space. (T.D. VAN GOLF-RACHT, 1982)

Fundamental it's obvious that the porosity of the matrix is different from that of fractures or the volume occupied by the networks of fractures and matrix blocks given by their relative volumes as a continuation.

$$V_f = \frac{totalvolumeoffractures}{totalvolumeofthesample} \quad (1)$$

$$V_m = \frac{totalvolumeofthematrixblocks}{totalvolumeofthesample} \quad (2)$$

$$V_m + V_f = 1 \quad (3)$$

Fractured reservoirs are characterized by double porosity, and the total porosity (ϕ_t) is the result of the simple addition of the primary and secondary porosities,

$$\phi_t = \phi_1 + \phi_2 \ (4)$$ [1]

This total porosity is equivalent to the static definition of rock storage or total void space, the fracture porosity was considerably less than the matrix porosity. The two porosities are expressed by the conventional definitions:

On which,

ϕ_1: matrix void volume/total bulk volume.

ϕ_2: fracture voids volume/total bulk volume.

Double porosity is also important in dynamic evaluations, where storage capacity is used instead of rock storage. The combined parameters of porosity and storage capacity, which

[1] : Asmund Haugen, Fluid Flow in Fractured Carbonates: Wettability Effects and Enhanced Oil Recovery, p 145.

show the total expansion and/or compression capacity of the fluid and rock void volume, are used to express this parameter.[1]

The significance of fracture porosity is determined by the type of fractured reservoir. In reservoirs where fractures provide essential porosity and permeability, it is critical to know the storage volume of the fracture network as early as possible in order to evaluate the reservoir and design a proper development plan.

In fractured reservoirs where the fractures have little storage volume and only provide permeability, knowing the fracture porosity is not important, if not negligible. In such systems, the matrix porosity is usually several orders of magnitude greater than the fracture porosity, making an early estimate of the fracture porosity irrelevant.

Because of the significant difference in the importance of fracture porosity, the reservoir type should be determined as early as possible. Let be the fracture porosity and the matrix porosity, then the storability dimension less parameter;

$$\boldsymbol{\omega = \frac{\phi_f C_f}{\phi_f C_f + \phi_m C_m}} \qquad \textbf{(5)}$$

It is the ratio of the fracture network's storage capacity to the total storage capacity.[2]

b. <u>Permeability:</u>

The permeability of a porous rock is a measure of the ability to transmit fluids. A reservoir can have primary and secondary permeability. The primary permeability is called matrix permeability, and the secondary permeability can be called fracture permeability or solution vugs permeability. Matrix-fracture permeability is another important parameter that must be known to estimate the influence of the fractures on the overall reservoir performance. Solution vugs permeability refers to increased permeability in matrix rocks (especially in carbonate reservoirs) where the natural permeability of the matrix is increased by percolation of acid waters that dissolve the matrix rock. The permeability in these flow channels can be calculated by combining Darcy’s law for fluid flow and Poiseuille’s law for capillary flow. Open fractures in Naturally Fractured Reservoirs generally have a higher permeability than the matrix, building the flow channels of the system. Lamb’s law can calculate the flow rate through a narrow cleavage:

[1] : Previous reference, p 149.
[2] : Zoltan E. HEINEMANN, Natural fractured reservoir engineering, Professor Heinemann Doktorandengruppe, p 16.

$$q = -\left(\frac{w^2}{12}\right)\frac{A}{\mu}\frac{dp}{dx} \qquad \textbf{(6)}$$

Where W is the effective fracture aperture (fracture width). The fracture cross-section **A** is the product of the fracture width W and the breadth **b**:

$$A = w.b \qquad \textbf{(7)}$$

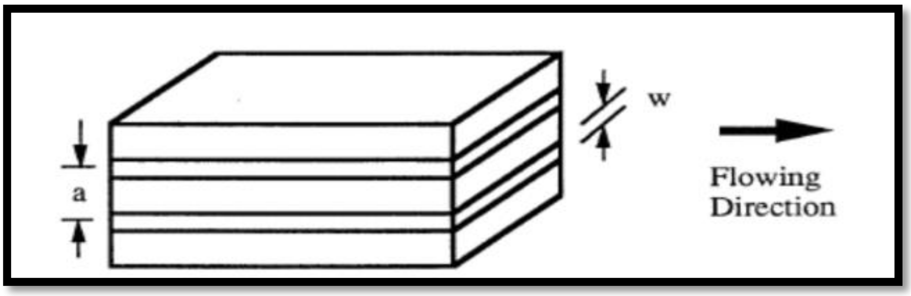
µ is the viscosity, and dp/dx is the pressure gradient. The Darcy equations can also express the flow rate:

$$q = -k\frac{A}{\mu}\frac{dp}{dx} \qquad \textbf{(8)}$$

Both Equation 6 and Equation 8 are valid for laminar flow. So it is evident that the permeability of a single fracture is:

$$k = \frac{w^2}{12} \qquad \textbf{(9)}$$

According to Aziz, a fracture with 10^{-5} m width (i.e., 0.1 mm) has a permeability of 844 Darcy. As a consequence of Equation 6 and Equation 7, between two flat plates, the flow rate is proportional to the cube of the aperture *W*. This is naturally not valid for natural fractures because they are rough.



<u>Figure1.5</u>: Parallel fracture in flow direction. (Zoltan E. HEINEMANN and Dr. Georg Mittermei, 2014)

The effective permeability in a fractured solid cube, shown in the figure above, is:

$$kef = kf\ \frac{w}{a} \qquad \textbf{(10)}$$

Where:

$$\frac{w}{a} = \phi \qquad \textbf{(11)}$$

Which it is the fracture porosity, inserting Equation 10 in Equation 11 results in the following?

$$Kef = \phi f\, kf \qquad (12)$$

Note that as a consequence of the Equations, the effective permeability is proportional to the cube of the aperture *W*:

$$kef \propto w^3 \qquad (13)$$

If the matrix is also permeable, then the overall effective permeability is:

$$ke = kef + (1 - \phi f)km \approx kef + km \qquad (14)$$

The approximation is valid if $\phi f \ll 1$

Equations 10 and 11 cannot be used for real fractures in porous rocks because it is derived for steady state, isothermal, and laminar flow between parallel glass plates. Similar to fracture porosity, fracture permeability is highly scale-dependent. A fracture of width W expressed in inches has a permeability of:

$$kf = 54\,.\,10^6.\ w^2 \qquad (15)$$

The resultant intrinsic permeability of a fracture of 0.01 in. would be 5400 Darcy's. The intrinsic permeability of Equation 15 is valid for a single point. The formulation can be extended for the bulk properties of the system for one set of parallel fractures:

$$k2 = \frac{kf\,.w0}{D} \qquad (16)$$

Where, D is the distance between the fractures.[1]

c. <u>Compressibility:</u>

In a fractured reservoir, the compressibility of a rock system plays an important role, especially if there is a great contrast between the two porosities of matrix and fractures ($\phi_f << \phi_m$). The role of compressibility is essential in the interpretation of the transient pressure behavior resulting from well testing. In this case, compressibility associated with the double porosity system is expressed by the storage capacity parameter, which extensively controls pressure behavior. Compressibility is, in general, defined as the change **ΔV** per unit of volume **V** for an applied pressure **ΔP**;

[1] : Previous reference, p 16-18.

$$C = -\frac{1}{V}\frac{\Delta V}{\Delta P} \qquad (17)$$

According to volume **V,** to which it may refer, compressibility may represent a property of a certain rock volume submitted to compression, such as a bulk volume (V_b) or only to the pore (V_p) or fluid volume (V_f).

The change in volume due to the variation of effective net pressure P_{eff} results from a change, either in overburden stress Ω (while the pore pressure P remains constant) or a change in pore pressure P (while the overburden pressure Ω remains constant). A change in pore pressure gives the usual case during reservoir production history,

$P_{eff} = \Omega - P$, as the result of reservoir depletion.[1]

d. <u>Fracture-matrix interaction:</u>

The hydrocarbon volume present in the high permeability fractures will be produced rapidly. After this "flush oil" production the rate will decrease rapidly before stabilizing at a lower decline rate. Fracture spacing and the amount of communication between the fracture and the matrix, as well as the drive mechanism will control the stabilized rate. Depending, generally, on the contrast between matrix and fracture permeability and fracture spacing, the classical single continuum description may not be adequate for the simulation modeling of a fractured reservoir. For theoretical analysis and reservoir simulation, the irregular fracture distribution must be replaced by a regular matrix network (primary porosity) floating in the interconnected fractures (secondary porosity continuum).[2]

3.2.<u>Reservoir-rock properties:</u>

a. <u>Wettability:</u>

Wettability is one of the most decisive factors in dealing with dual-porosity fractured reservoirs, which plays an important role in oil and gas production as it not only determines the initial fluid distributions but also is a major factor in the flow processes within the reservoir rock. It fundamentally influences the fracture-matrix interaction and, therefore, the ultimate recovery factor.

[1] : T.D. VAN GOLF-RACHT, Fundamentals of fractured reservoir engineering, ELSEVIER publishing USA, p 199-204.
[2] : Narr Wayne, David S. Schechter, and Laird B, Thompson; Naturally fractured reservoir characterization; Richardson, TX: Society of Petroleum Engineers, p 155.

The wettability of a reservoir-rock fluid system is the ability of one fluid to spread on the rock's surface in the presence of another. The degree of wetting of solids by liquids is usually measured by the contact angle that a liquid-liquid interface makes with a solid. A fluid drop on a plane or solid surface can take various shapes. The respective shape (either flat or shaped like a pearl) depends on the wettability of the considered solid.

In the case of air and water, the water is the wetting fluid; for air and mercury, the air is the wetting fluid.

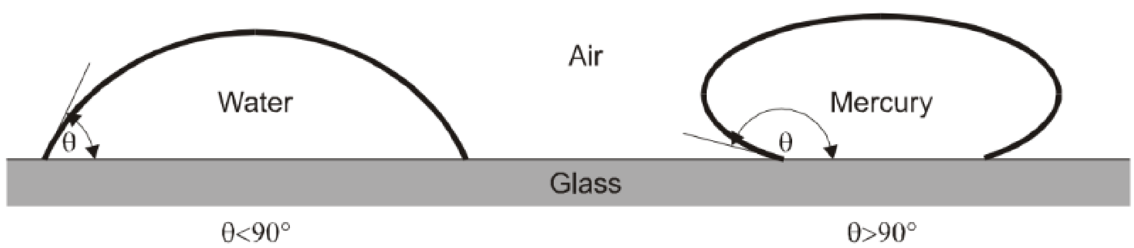


Figure1.6: Comparison of wetting and non-wetting fluids. (Zoltan E. HEINEMANN and Dr. Georg Mittermei, 2014)

The contact angle, θ, is used as a measure of wettability. In the case of a wetting fluid, the contact angle is smaller than 90°. If the contact angle is larger than 90°, then the fluid is called non-wetting.

Interfacial tensions $\boldsymbol{\sigma_{pp'}}$ between the fluids **p** and **p'**, and thus the contact angle, θ, are temperature-dependent. At room temperature, the interfacial tension between water and air is 0.073 N/m and between oil and water, about 0.03 N/m.

The wettability of a reservoir rock system depends on many factors:

- Reservoir rock material.
- Pore geometry geological mechanisms.
- Composition and amount of oil and brine.
- Pressure and temperature.
- Changes in saturation, pressure and composition during production.

When determining whether an oil reservoir's rock is water- or oil-wet, it is important to consider the specific rock and fluid properties. Intermediate- or neutral-wet rocks are neither water- nor oil-wet. The table below demonstrates that while sandstone reservoirs can be either water- or oil-wet, carbonate reservoirs are often oil-wet.[1]

Table 1: Reservoir wettability based on contact angle measurements. (Zoltan E. HEINEMANN and Dr. Georg Mittermei, 2014)

Wettability	Contact Angle	Number of reservoir investigated		
		Sand	Carbonate	Total
Water-wet	0-75	13	2	15
Intermediate-wet	75-105	2	1	3
Oil-wet	105-180	15	22	37

A reservoir rock's internal surface is composed of various minerals with different surface chemistry and adsorption characteristics, which may cause variances in wettability. Several authors have put up the idea of fractional wettability, often known as heterogeneous or spotted wettability. It should be noted that the intermediate wettability, which assumes that all areas of the rock surface have a slight but equal preference for being wetted by water or oil, varies conceptually from the fractional wettability.

A special type of fractional wettability called mixed wettability occurs when the oil-wet surface creates continuous pathways via the larger pores. Smaller pores do not contain oil and continue to get wet with water. Salathiel explained that oil invading an originally water-wet reservoir displaces water from the larger pores while the smaller pores remain water-filled. If the oil only deposits a film of oil-wet organic material on solid surfaces in direct contact with the oil and not on surfaces that contain water, this is known as a mixed-wettability condition.

b. <u>Capillary pressure:</u>

The figure below shows regular capillary functions for primary, imbibition and secondary drainage. They apply to the inter- and intra-granular matrix. Two of these functions are used to determine the wettability by the U.S. Bureau of Mines (USBM) method developed by Donaldson. [2]

[1] : Zoltan E. HEINEMANN, Natural fractured reservoir engineering, Professor Heinemann Doktorandengruppe, p 22-23.
[2] : Previous reference, p 23-24.

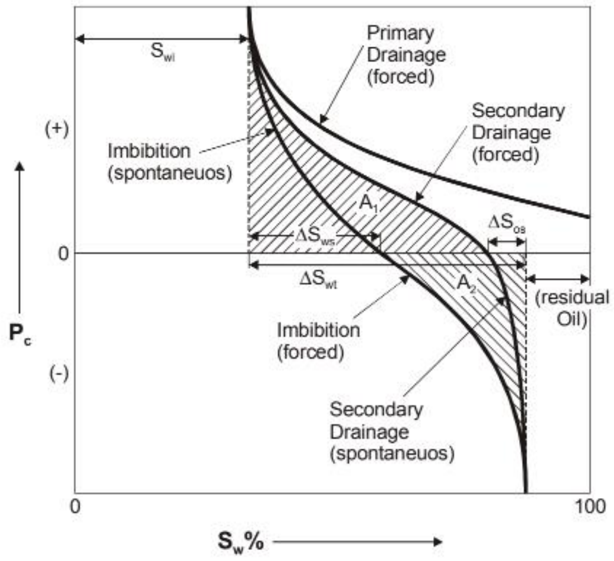


Figure 1.7: Typical capillary pressure curves and the relationships of wettability measurements by Amott and USBM tests to Pc. (T.D. VAN GOLF-RACHT, 1982)

The capillary pressure curve plays a much more important role in a fractured reservoir than in a conventional reservoir. Capillary forces in fractured reservoirs are an extremely important component of the driving mechanism, while the dynamic role of the capillary forces in a conventional reservoir is more limited. In a fractured reservoir, capillary forces may contribute to the displacement process inside the imbibition process or may oppose it in the drainage displacement process.[1]

c. Relative permeability:

It is commonly assumed that the immobile saturations (S_{wc}, S_{or}, and S_{gc}) in the fracture are zero and that the relative permeability is a linear function, as shown in Figure 1.11. This is unquestionably true for a single fracture, but it is questionable for a fracture network. The fracture orientation will also be important in this regard. This is illustrated in Figure 1.12. Furthermore, the history matching practices indicate that relative permeability in fractures is not a linear function of phase saturations. This could be because the relative permeability of a fracture network differs from that of a single fracture.

The segregation of phases is a possible assumption in high-permeability fractures. Under these conditions, the relative permeability in lateral fracture-fracture and fracture-matrix connections could equal phase saturation. This is certainly not true in the vertical direction,

[1] : T.D. VAN GOLF-RACHT, Fundamentals of fractured reservoir engineering, ELSEVIER publishing USA, p 233.

where the lighter phase's relative permeability becomes 1, and the heavier phase becomes 0. On the bottom, the inverse is true.

It should be understood that predicting the relative permeability of a fracture in a real field is impossible. The practical approach could be to use the well-established model for the relative permeability function of water and oil: Nonlinear fracture relative permeability influences inter-block flow and matrix-fracture transfer (upstream values). As a result, the water-oil capillary pressure favors water imbibition into the matrix blocks, whereas the gas-oil capillary pressure prevents gas from entering the matrix block. Gas is unable to displace oil from matrix blocks without proper transfer treatment. The Corey-exponent representation is an established model for the relative permeability functions of water and oil:[1]

$$\mathbf{K_{rw}\,(S_w) = k_{rw\,@Sor}} \left(\frac{Sw-Swi}{1-Swi-Sor}\right)^{Nw} \qquad \textbf{(18)}$$

$$\mathbf{K_{ro}\,(S_w) = k_{ro\,@Swi}} \left(\frac{1-Sw-Swi}{1-Swi-Sor}\right)^{No} \qquad \textbf{(19)}$$

Where:

$\mathbf{k_{rw@Sor}}$and $\mathbf{k_{ro@Sw:}}$ end-point relative permeability’s, usually both are1.

$\mathbf{N_W}$ and $\mathbf{N_{o:\,Corey}}$ exponents for water and oil,

$\mathbf{S_w}$: water saturation,

$\mathbf{S_{wi}}$: connate water saturation, usually 0.

$\mathbf{S_{or}}$: residual oil saturation, usually 0.

Typical Corey exponents for inter-granular porosity are summarized in the Table below. The exponents $N_w = N_o = 1$ result in straight-line functions. No serious suggestions have been published on which values would be used for fracture networks.

PRS applies the exponents $N_w = 1$ and $N_o = 2$ as default values. Analogously an exponent of Ng= 2 is used for the gas relative permeability. Moreover, the immobile phase saturations (S_{wir}, S_{gc}, S_{or}) are not 0 but 0.01.

[1] : Previous reference, p 26.

Table 2: Typical values for Corey exponents N_o and N_w. (T.D. VAN GOLF-RACHT, 1982)

Wettability	N_o	N_w
Water-wet	2-4	5-8
Intermediate-wet	4-6	3-5
Oil-wet	6-8	2-3

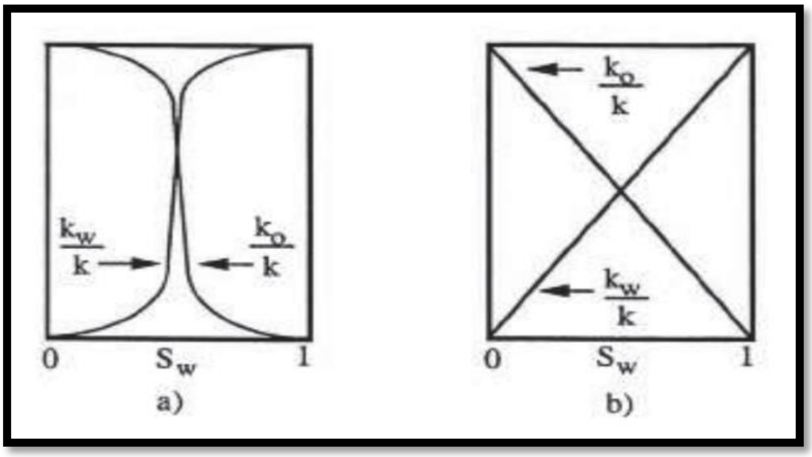


Figure1. 8: Relative permeability's for: a) cores with fractures non parallel to the flow, b) cores with fractures parallel to the flow. (T.D. VAN GOLF-RACHT, 1982)

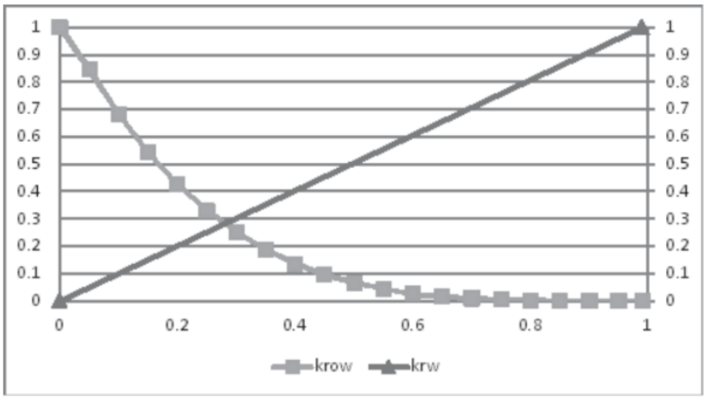


Figure 1.9: PRS default fracture relative permeability functions (calculated from Corey equation $N_W = 1$ and $No = 2$).T.D. VAN GOLF-RACHT, 1982) [1]

[1] : Previous reference, p 27-28.

4. Importance of the Naturally Fractured Reservoirs:

The naturally fractured reservoirs (NFRs) present 40% of oil and gas reserves worldwide.

It is an excellent source regarding proved, probable and possible oil and gas reserves in these reservoirs. However, the estimation of the reserves in these reservoirs is complex.

The studies recommended employing statistical procedures to estimate the uncertainty of hydrocarbons-in-place and reserves in naturally fractured reservoirs.

Most naturally fractured reservoirs have low matrix porosities (less than 10%) and low matrix permeabilities (less than 1 md).

It is difficult to establish a reasonable assurance in volumetric estimations of original hydrocarbons in place for these reservoir characteristics and, thus, reserves. As a result, it proposes initially categorizing reserves based on volumetric estimates. Reserves can be transferred to the probable category if the matrix porosity is greater than 10% and the matrix permeability is more significant than1 md.

Estimates of probable reserves can be obtained from early material balance calculations. The material balance reserves can be placed into the proved category when cumulative production increases and with good-quality pressure data improves (long flow and long shut-in times).

Its place production decline estimates from short history in an unproved category. [1]

A long history of production results in realistic estimations of proven oil reserves. Using decline curves to estimate proved reserves of gas reservoirs isn't recommended to use decline curves to estimate proved reserves of gas reservoirs unless the wells are at a late production stage where a constant surface compression pressure is being utilized.

Reservoir simulation, although imperfect, is the tool that provides the most reliable source of information for estimating recoveries and proving reserves. A significant amount of high-quality data and rigorous characterization are required. The longer the production history, the more reliable are the forecasted results.

Proved reserves can be determined early in the reservoir's life, when production history is limited or non-existent, using well-designed, well-supervised interference tests with high-precision pressure gauges. A significant number of wells in the test were used for better estimation. In addition to reserves, the test will provide helpful information about anisotropy.

If the objective is to estimate reserves by evaluating both matrix and fractures, pulse tests with the short flow and buildup durations are not recommended. During matrix and fracture

[1]: Roberto Aguilera, Recovery Factors and Reserves in Naturally Fractured Reservoirs, the Petroleum Society Monograph No.1, p 4.

interference tests, continuous flow periods are essential to investigate both matrix and fractures properly.

If there is only one well in the naturally fractured reservoir, an extended flow period following the collection of good kicking-off pressure is recommended. A volumetric estimate of hydrocarbons in place within the studied area is obtained by estimating the radius of the investigation. A reasonable estimate of net pay, matrix and fracture porosity, and matrix and fracture hydrocarbon saturation is required.[1]

[1] : Roberto Aguilera, Recovery Factors and Reserves in Naturally Fractured Reservoirs, The Petroleum Society Monograph No.1, p 4.

Chapter II:

The key parameters affecting the selection of Enhanced Oil Recovery for the Naturally Fractured Reservoirs

1. Introduction:

Enhanced Oil Recovery (EOR) techniques are frequently employed and have a relatively high percentage of improving oil production.

The EOR is a production tertiary recovery technique that seeks to produce the trapped oil that would not be recovered using the primary and secondary recovery methods where the oil has stopped flowing or the water content of the oil reservoir increased.

Chemical, thermal, and gas injection are the three main techniques frequently utilized; the chosen technique relies on the reservoir and fluid characteristics.

However, the current challenge is researching the efficient EOR technique appropriate to apply on the NFR to improve the recovery factor.

2. An overview of the Enhanced Oil Recovery techniques:

Gas, thermal, and chemical injections are the three most commonly used EOR techniques. Although most gas injection applications are designed to be miscible, they might also be immiscible. Moreover, the gas injected may be nitrogen, carbon dioxide, or natural gas (CO2). Heat is introduced during thermal injection; all other methods are ineffective. Chemical injection, often known as "improved oil recovery," involves altering the fluid/rock interface properties and is considered significant to water flooding. Over the past few decades, less than 1% of all EOR production has come via chemical recovery. Moreover, microorganisms are used in microbial processes to assist oil recovery. [1]

2.1. Gas injection:

The most widely utilized technique for increased oil recovery is the gas injection, commonly known as miscible flooding. This initiative was because gas injection enabled simple pressure maintenance without the cost of injected fluids. Miscibility took a lot of work to obtain. Thus it became common to purify the gas that was injected.

Moreover, liquid nitrogen injection became common in several projects. When the interfacial tension between oil and water is reduced, a miscible displacement technique keeps reservoir pressure constant while enhancing oil displacement.

The interface between the two interacting fluids has been removed.

It is equivalent to having total displacement efficiency to have a miscible fluid. Because carbon dioxide injection has the added benefit of "greenhouse gas sequestration," it has

[1] : M.R.Islam, Economically and Environmentally Sustainable Enhanced Oil Recovery, Scrivener publishing, USA, p461.

become the preferred EOR fluid in the current "hysteria" regarding climate change. As a result, CO2, natural gas, or nitrogen is currently the most widely used gases. Carbon dioxide is the fluid most frequently used for miscible displacement because it lowers oil viscosity and costs less than liquefied petroleum gas.

The phase behavior of the CO2 gas and the crude mixture is strongly influenced by reservoir temperature, pressure, and crude oil composition, which is necessary for oil displacement by carbon dioxide injection. Moreover, the liquid phase swells in the presence of CO2, which increases motility. The majority of predictions for miscible flood recovery consider first-contact miscibility. Yet in practice, it's always multiple-contact, and for heterogeneous formations, the miscibility often only occurs for narrow transition zones.[1]

2.2.<u>Thermal injection:</u>

Thermal methods increase the temperature of certain reservoir regions, which heats the crude oil in the formation, reduces its viscosity, and partly vaporizes it; this decreases the mobility ratio. Thermal techniques include conducting in-situ combustion of gas or oil and injecting hot water, steam, or other gases.

The improved reservoir seepage conditions are caused by reduced surface tension, increased oil permeability, and increased heat. It's also possible for heated oil to vaporize and then condense, producing improved oil.

However, this strategy necessitates a substantial investment in specialized tools. Both thermal recovery techniques pose safety risks during the more involved production process and significantly damage the subsurface well construction. These factors lead to the methods typically being used sparingly. The two main types of thermal recovery are steam flooding and gas drive oil.[2]

2.3.<u>Chemical injection:</u>

In a chemical flood, chemicals are injected with water to improve displacement efficiency. A chemical solvent is specifically created to adjust to a reservoir's unique structural traits and physicochemical characteristics.

After injecting with water, chemical reactions from new chemical sediment reduce the contradiction between layers and increase the volume and amount of water injected. This could increase the amount of reserves that can be recovered while enhancing production effectiveness.

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[1] : Previous references, p462.

[2] : Sino Australia oil & gas Pty Company, an introduction to enhanced oil recovery techniques, p6.

Unfortunately, this kind of chemical reaction would occur in a poor reservoir, causing oil contamination and damaging the ability to absorb water. These techniques could be more effective for most wells, with the adverse effects outweighing the positive outcomes.

The main chemical injection widely used is polymer injection. [1]

2.4.<u>Microbial Injection:</u>

A new biological theory proposes injecting bacteria into the oil reservoir to increase the effectiveness of oil recovery. The metabolism of a considerable population can produce significant amounts of organic acids, according to experiment results utilizing a specific species in a reservoir. Thesis Organic acids dramatically improve oil recovery, enhance productivity, and revitalize ageing wells.

To achieve microbial injection, three techniques have been employed. The first method injects bacterial cultures into the oil field with a food source (often a carbohydrate like molasses).

The second approach, used since 1985, involves injecting nutrients into the ground to feed already-existing microbial bodies. These nutrients induce the bacteria to produce more natural surfactants that they usually use to metabolize crude oil underground. The bacteria enter a state of near-shutdown once the injected nutrients are consumed. They then migrate to the oil-water interface region, where they induce oil droplets to develop from the larger oil mass.

The oil droplets are then more likely to go toward the wellhead as a result.

The third approach deals with the issue of the crude oil's paraffin wax components, which tend to precipitate as the crude flows to the surface. A temperature reduction of 9–10–14 °C per thousand feet of depth is typical because the Earth's surface is significantly colder than the petroleum deposits.

Microbial injection, a part of microbial-enhanced oil recovery, is hardly utilized due to its higher cost and the fact that the technology is not widely accepted.

These microorganisms produce bio-surfactants or emit carbon dioxide after partially digesting lengthy hydrocarbon molecules.[2]

The figure below indicates the different EOR techniques utilized:

[1] : Previous reference, p 3.

[2] : Previous reference, p 7-8.

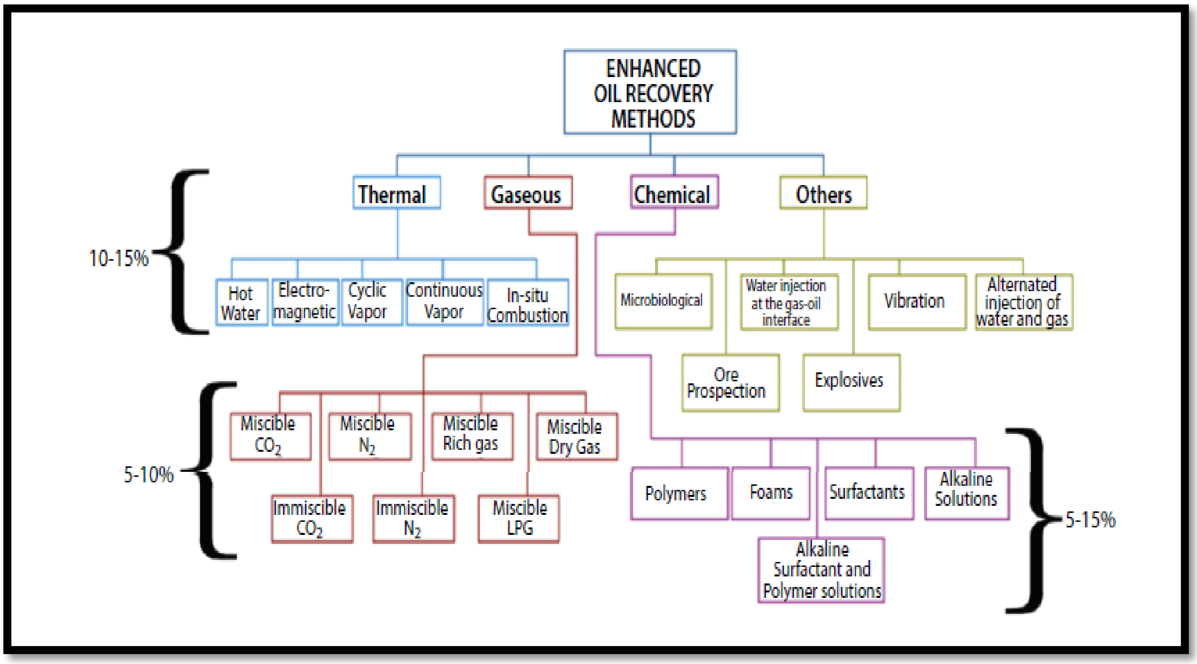


Figure 2.1: Various available EOR methods, with their recovery percentage, (M.R.Islam, 2013)

3. The key parameters affecting the selection of the Enhanced Oil Recovery for the Naturally Fractured Reservoirs:

Applying the CO2 injection on the NFRs should consider the key parameters that can affect the performance of the CO2 injection on these reservoirs.

The table below demonstrates the key parameters affecting the CO2 injection on the NFR.

Table 3: the key parameters affect the CO2 injection in the NFR.

Reservoir Properties: - Reservoir heterogeneity (permeability & porosity). - Fracture properties (density, geometry…etc.) - The geological lithology of the reservoir. - Oil Saturation.	**Fluid Properties:** - Specific gravity (API) - Oil Viscosity - Oil compositions. - The state of the injected CO2 at reservoir conditions (P,T).
Reservoir-Fluid Properties: - Wettability. - Capillary pressure & relative permeabilities (matrix & fracture).	**Operational Conditions:** - Miscibility (MMP). - Injection rates. - Injection modes (design).

However, we will consider just four parameters to investigate their effect of them on CO2 performance, which are: fracture density, wettability, and miscibility and injection design. On the following points, we will discuss the important parameters that affect it by order.

3.1.<u>Impact of wettability:</u>

Wettability is the tendency of the liquid to spread on a solid surface. In enhanced oil recovery, wettability plays an important role as that determines the interactions between the solid (rock) and the liquids in the reservoirs (crude oil, brine and EOR fluids). Wettability has been recognized as one of the key parameters controlling the remaining oil-in-place, which determines the displacement process.

In order to investigate the impact of the wettability on the performance of the CO2 injection on the NFRs to improve the recovery factor on the NFR, an experimental study was done in Indonesia by Muhammad Ali, Sarmad Al-Anssari and others, titled Influence of Miscible CO2 Flooding on Wettability and Asphaltene precipitation in Indiana Limestone. On which they focused on the interaction between CO2-crude oil (light, medium and heavy) on the same carbonate rock at reservoir conditions to see its effect on the wettability. The results show that:

The lighter crude oil reservoirs produce more oil compared to heavier ones. When CO_2 is injected above supercritical pressure, it dissolves into crude oil by reducing its viscosity and increasing the swelling, which is one of the reasons for more oil recovery. [1]

<u>Table 4</u>: Summary of CO2 solubility, Oil swelling factor and Minimum Miscibility Pressure of CO2 (Muhammad Ali, Sarmad Al-Anssari and others, 2017).

Crude Oil	Oil Volume (cc)	Volume of CO2 dissolved (cc)	CO2 Solubility(cc/cc)	Oil swelling factor (%)	Minimum Miscibility Pressure of CO2 (Psi)
40°API	20	931	1.2879	12.81%	1400
34°API	20	979	1.3504	30.43%	1500
29°API	20	1029	1.4201	36.35%	1600

[1]: Muhammad Ali, Sarmad Al-Anssari and others, Influence of Miscible CO_2 Flooding on Wettability and Asphaltene Precipitation in Indiana Limestone, SPE-186204-MS, p 6.

On which the crude oil composition plays an important role in determining the wettability alteration, which is the case for heavy crude oil; the wettability altered from oil-wet to intermediate-oil wet indicates the reduction of the oil recovery.

Table 5: CO2 flooding experimental results of all crude oils, (Muhammad Ali, Sarmad Al-Anssari and others, 2017).

Crude Oil	S_{wi} (%)	S_{or} (%)	Total CO2 Pore Volume Injected	Pore Volume of CO2 injected at breakthrough	Oil Recovery at CO2 breakthrough point (%)	Net Oil Recovery (%)
40°API	**22.92**	**41.47**	**2.78PV**	**0.46PV**	**31.11**	**68.02 %**
34°API	**14.43**	**46.39**	**2.39PV**	**0.38PV**	**23.32**	**59.14 %**
29°API	**9.91**	**51.85**	**1.94PV**	**0.21PV**	**18.97**	**%**

In conclusion, the CO2 and oil interaction may affect the wettability by causing its alteration that will affect the oil recovery either positively or negatively. Because the CO2 dissolves in the oil due to its miscibility causing viscosity reduction, oil swelling and wettability alteration if the oil contains a large amount of heavy components.

3.2.<u>Impact of injection design, Miscibility and Fracture density:</u>

In order to investigate the impact of fracture density, miscibility and the injection design on the performance of the CO2 injection to improve the recovery factor on the NFR, an experimental study was done in China by Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen on "Experimental Study on CO2-EOR in Fractured Reservoirs: Influence of Fracture density, miscibility and Production Scheme. On whichthree CO2 flooding tests in the unfractured system and nine groups of CO2 flooding and subsequent CO2 HnP tests in the matrix-fracture system were conducted varying experimental conditions to examine the performance of CO2 EOR, and the following parameters were systematically investigated:

1) Fracture density (0, 2.5, 5.0 and 8.3 fractures per meter, which the fractures are vertical)
2) Miscibility (immiscibility, multi-contact-miscibility and first-contact-miscibility),
3) Production scheme (CO2 flooding and HnP).

The results showed in the next table.

Table 6: Experimental conditions and summary of CO2 flooding and HnP results. (Mingchen Ding, Miao Gao, Yefei Wang, ZhengtianQu, Xu Chen, 2018).

Core No.	Injection pressure (MPa)	Miscible condition	Fracture density (fractures per meters)	Oil phase	Oil in place (cc)	Initial oil saturation (%)	RF. CO2 flooding (%)	RF. CO2 HnP (%)	RF. Total (%)
#1	17,5	**IM**	**0**	**Crude Oil**	5	52,1	65,6	0	65,6
#2			**2,5**		9,8	50,4	11,8	45,1	56,9
#3			**5**		4,9	49,7	16,3	40,9	57,2
#4			**8,3**		2,9	48,3	28,4	30,8	59,2
#5	25	**MCM**	**0**	**Crude Oil**	4,8	50,5	78,9	0	78,9
#6			**2,5**		9,6	49,1	14,4	71,3	85,7
#7			**5**		4,9	48,7	20,2	66	86,2
#8			**8,3**		3	50	47,2	38,7	85,9
#9	25	**FCM**	**0**	**Tetrad-cane**	4,8	49,5	93,4	0	93,4
#10			**2,5**		9,7	50,3	22,1	48,7	70,8
#11			**5**		4,8	48,2	48	25,8	73,8
#12			**8,3**		2,9	48,3	68,1	6,3	74,4

Taking into consideration that the MMP for oil\CO2 is 17.8 MPa at 60 ^{0}C. The tetradecane is selected to achieve FCM CO2 injection at relatively low pressures, on which the MMP for tetradecane\CO2 is 8.5 MPa at 38 ^{0}C and 12.7 MPa at 62 ^{0}C. (MMP=12.35 MPa at 60 ^{0}C)

After these results, we observe the following:

- For the first five cores with the immiscibility conditions under an injection pressure of 17.5 MPa under the MMP: the oil phase utilized is crude oil, with different oil in place & saturation values. The results indicate that:
- The increasing fracture density for fracture and unfractured conditions follows a variation of the RF on the continuous CO2 injection and the CO2 HnP with no values on the unfractured conditions.
- For the following three cores with the MCM conditions under pressure of 25 MPa above MMP: the oil phase chosen is the crude oil, with different oil in place & saturation values. The results indicate that:
- With the increase of the fracture density, there is an increase in the RF for the continuous injection and a decrease in the HnP injection.

- For the last three cores with the FCM conditions under pressure of 25 MPa, the oil phase utilized is the tetradecane with different oil in place & saturation values. The results indicate:

  With the increase of the fracture density, there is an increase in the RF for the continuous injection and a decrease in the HnP injection.

  The RF achieved the maximum values on the unfractured conditions for the CO2 continuous injection, with no value recorded on the HnP injection.
- The HnP have a significantly higher amount of RE, about 45.1% and 71.3% for 2,5 fracture per meter for IM and MCM conditions, respectively, than the flooding injection. However, the flooding injection has higher RF for the FCM conditions, about 48% more than the HnP RF that recovered on five fractures per meter conditions.

After these observations, we indicate that the fracture density has a positive effect on the CO2 continuous injection, which with the increase of the density fracture, the RF increased. However, it dramatically affects the HnP injection, which causes the fracture density to increase and the RF to decrease. And the miscibility condition affects the RF improvement for both production schemes.

4. <u>Discussion:</u>

After analyzing the key parameters affecting the CO2 injection on the NFR, we can order them within the most affecting parameters:

a. The wettability.

b. Injection design.

c. Miscibility.

d. Fracture density.

We can say the wettability is the most key parameter affecting the CO2 injection because

It determines the displacement process, which can alter certain conditions of the interaction of CO2/oil that will affect the recovery factor.

Furthermore, the injection design of CO2 can improve the recovery factor; especially the HnP process shows a significant improvement in the oil recovery. The studies show that CO2 can be injected in an immiscible mode or miscible way; however, the miscible conditions improve higher RF than IM conditions.

Then, the fracture density effect demonstrates that effect for the CO2 injection design, which has a positive effect on the flooding injection but a negative effect on the HnP injection.

We order these parameters based on the analysis of the results that showed on the table 5 and the table 6.

Chapter III:

Comparison study of different Enhanced Oil Recovery methods vs. CO_2 injection applied on the Naturally Fractured Reservoirs.

1. Introduction

Naturally fractured reservoirs exist worldwide and represent significant amounts of Earth's oil and gas reserves, water, and other natural resources. In the past half-century, the study of fluid flow and transport processes in fractured porous media has received great attention. It has been one of the most active areas investigating multiphase flow in subsurface reservoirs. This is because of its importance to underground natural-resource recovery, waste storage and disposal, environmental remediation, CO2 geo-sequestration, and many other subsurface applications. The selection of the proper EOR method to be applied to the NFRs is challenging due to the complexity of its properties.

2. Enhanced Oil Recovery techniques applied on the naturally fractured reservoirs:

2.1. Chemical flooding:

In chemical flooding, the fluid inside fractures may displace the oil from the matrix via viscous, capillary, and gradual mass transfer. If enough aqueous chemical solution is supplied in fractures in a water-wet NFR, capillary imbibition may significantly contribute to the oil recovery. Hence, the key to recovering oil is the wettability alteration to preferentially water-wet conditions. Anionic surfactants can be used to shift the wettability of carbonates towards a water-wet state. Gravity drainage may become the dominant mechanism in the absence of capillary imbibition. In gravity drainage, the surfactant molecules enter from fractures into the matrix via diffusion and convection. This changes the wettability and reduces the Interfacial Tension (IFT). Consequently, gravitational forces overcome the entry capillary pressure, and water invades the matrix and pushes the oil from the top. Furthermore, injecting surfactant solution into oil-wet NFRs increases the oil's relative permeability, enabling gravity to drain the oil. Finally, since carbonate formations are normally positively charged; therefore nonionic and cationic surfactants are appropriate to reduce surfactant adsorption. The alkali can also be used to reduce the adsorption of the surfactant. Based on chemical flooding pilot projects in NFRs, foremost factors have been identified to optimize the chemical flooding performance. The primary step to evaluate the efficiency in a large pilot or field is to run single well tests. Also, profile modification using cross-linking gels is a possible candidate to reduce the water cut in the preferentially oil-wet NFRs. Another suitable candidate might be treating wells with surfactant washes towards a large wettability alteration. Before performing any surfactant treatment, matrix stimulation might be necessary to improve the near well-bore response further. Like a surfactant-based chemical huff-n-puff process, a wettability-shifting process can also be carried out with different alkali/surfactant formulations. [1]

These two robust measures can reduce the water cut and improve oil production. Finally, the main challenge of chemical flooding is the presence of fractures and vugs, which may prevent a uniform sweep and cause excessive chemical loss. Thus, chemical loss to the fractures must be considered to design the optimum slug size. Moreover, the chemical slug composition should be optimized for high oil recovery.

The field projects of chemical flooding in NFRs have revealed several factors which should be considered to design a successful flood. Several measures should be taken to assess the performance of chemical flooding. These include the tracer test, pressure fall-off test, temperature survey, monitoring water and oil production, and monitoring wellhead pressures and injection rates. In some NFRs, problems are associated with clay swelling, migration, and fractures. Clays swelling and migration limit injectivity and force all the injected fluids into the fractures, causing premature breakthroughs and poor sweep efficiency. The measures to overcome these obstacles are stabilizing the clays, reducing the fracture flow, and maximizing the imbibition. To maximize the imbibition, pre-injecting alkali is an option. Also another option is adding a wettability adjustment agent, such as a blend of an anionic polymer and an alkali. It is normally difficult to quantitatively measure the contribution of the wettability alteration in chemical flooding. However, the wettability adjustment is important in stabilizing a low water-oil ratio over a relatively long time. Field-scale experiences of polymer flooding show that if properly tailored to the reservoir condition, this process is an appropriate candidate for an NFR in which heterogeneities and high mobility ratios cause considerable oil bypassing. In addition, polymer flooding can be a candidate for a commercial project when the economics of surfactant flooding is unfavorable in the presence of extreme fracturing and heterogeneity. In such cases, polymer flooding can significantly improve oil recovery, although early polymer breakthroughs might occur. In particular, if an NFR is more matrix-dominated, then the performance of polymer flooding is more noticeable than that of an NFR influenced more by fractures with imbibition. The field projects have revealed several measures which should be taken to design a successful flood. First, a field test of polymer injectivity should be conducted to ensure injection without severe face plugging. A pressure

[1] : B. Yadali Jamaloei, Chemical Flooding in Naturally Fractured Reservoirs: Fundamental Aspects and Field-Scale Practices, Oil & Gas Science and Technology – Rev. IFP Energies nouvelles, Vol. 66 (2011), No. 6, p 5.

fall-off test is also useful for assessing potential near-well plugging problems. Second, if the polymer cycles through channels or fractures, care should be taken. If the polymer cycles through fractures and removes fines, then polymer breakthrough may cause tubular failure due to the entrained solids carried into the wellbore. In fact, oil recovery may decrease because of extensive polymer cycling. [1]

Finally, wellhead pressure should be carefully monitored during the flood. The reason is that an increase in wellhead pressure and an injectivity reduction may indicate that the resistance to flow is being built in higher permeability zones and microfracture networks. This increases sweep efficiency. The field projects of chemical flooding in NFRs have revealed the most effective methods to improve the sweep efficiency of chemical flooding in NFRs. One of the methods is in-depth conformance control using surfactant/ alcohol-based technology, which modifies the permeability in highly permeable zones. The surfactant-alcohol blends reduce the permeability contrast and divert the primary drive fluid to the target. The other method is the polymer-aluminum citrate-polymer injection sequence. This method works in the fractured zones to eliminate the direct channeling of injections to the producers. The field experiences show that the aluminum citrate cross-linker can minimize the direct channeling of polymer to the producers. [2]

2.2. Thermal injection:

Most naturally fractured reservoirs produced using thermal processes contain very low-mobility oil. Therefore heat conduction plays a very important role in the initial stages of production. With increasing oil mobility, convective gravity and capillary forces lake over if the matrix, permeability is fairly high or the reservoir is fractured extensively. [3]

It is highly affected by the reservoir and fluid properties.

2.3. Miscible gas:

Designing gas program is to optimize the properties of produced hydrocarbon gas by removing or adding other gases before injecting it back in the reservoir this can dramatically improve oil recovery, Miscible gas is usually made of carbon dioxide or hydrocarbon gas or a mixture of both, It is one of the most effective EOR methods for pore-scale displacement typically displacing 95% of the residual oil that it comes in contact with, when miscible gas

[1] : Previous reference, p 5.
[2] : Previous reference, p 6.
[3] : Shawket G. Ghedan and Anjani Kumar, Impact of Fractures Characterization, Wettability and Hysteresis on Thermal Recovery Processes in Carbonate Naturally Fractured Reservoirs, SPE-170189-MS, p 4.

comes in contact with the oil it exchanges components at the interface between the two so the gas gets heavier and looks more like oil and the oil gets lighter and looks more like the gas until finally the interface disappears the miscible performance of hydrocarbon gas can typically be improved by adding in more propane or butane, for example; in a water wet rock the residual oil is trapped in the middle of the pores because it has lost its flow continuity; miscible gas injection re-establishes that continuity by creating a new hydrocarbon flow path that enables the oil to flow out when the miscible gas flood id finally stopped water is injected to push the remaining gas out and gas takes the place of the residual oil in the pores while the oil is produced, miscible gas like normal gas is still very mobile in the reservoir so it is often injected alternately with water in a water alternating gas or WAG process, the water slows the gas down and also sweeps the rock lower down in the reservoir that the gas might not reach.

a. Carbon dioxide injection:

When the pressure in a reservoir is reduced due to primary and secondary production, carbon dioxide flooding can be an excellent tertiary recovery method. It is especially effective in reservoirs deeper than 2,000 feet, where CO_2 is supercritical.

When CO_2 is injected into the reservoir, it dissolves in oil; the oil swells and the viscosity of any hydrocarbon will be reduced, and hence, it will be easier to sweep to the production well If the well is suitable for CO_2 flooding, then. The pressure is maintained by water injection.

Then CO_2 is injected in these applications and between one-half and two-thirds of the injected CO_2 returns with the produced oil. This is then usually re-injected into the reservoir to minimize operating costs. Carbon dioxide as a solvent has the benefit of being more economical than other similarly miscible fluids such as propane and butane. Unless natural CO_2 exists in the near area, it’s generally difficult to collect sufficient amounts of CO_2 for industry use. [1]

b. Water-Alternating-Gas injection:

Water-alternating-gas (WAG) injection has been found to be an effective enhanced recovery mechanism for carbonate reservoirs. WAG combines the benefits of gas injection to reduce residual oil saturation and water injection to improve mobility control and frontal stability. Implementing dynamic miscibility during WAG could increase oil recovery even further by improving the microscopic sweep efficiency.

[1] : Bakhtyar Abdulstar ,Huner Mahdi , Muhammad Faisal, Improving Oil Recovery In Fractured Reservoirs (Eor), p12.

The effect of wettability on the WAG simulations cannot be neglected. Water-wet reservoir conditions reduce gas saturation in the matrix due to high capillary entry pressures that oppose gas-oil gravity drainage. Increased imbibition in the water-wet medium also leads to higher oil recovery from water injection cycles. Conversely, the imbibition potential is very poor in the oil-wet medium leading to much lower recovery from water injection cycles. Trapping of the non-wetting phase is also more significant in the water-wet media. This is because snap-off occurs, and gas becomes increasingly disconnected from the continuous gas phase in the pore throats. Because trapping entails a reduction of gas mobility, it ultimately leads to higher recoveries. Reducing the gas mobility delays gas breakthrough, increases the stability of the gas-water mobility front and improves contact of gas with residual oil, thereby ensuring better macroscopic and microscopic sweep of the reservoir. [1]

3. <u>Comparison study of Enhanced Oil Recovery methods vs. CO2 injection on the Naturally Fractured Reservoirs:</u>

3.1. <u>Comparison of CO2 injection vs. water flooding, hydrocarbon gas flooding and Water-Alternating-Gas flooding:</u>

In order to investigate the appropriate EOR mode to improve the oil recovery on the NFRs, a comparative study done by Saif S. Al Sayari, titled The Influence of Wettability and Carbon Dioxide Injection on Hydrocarbon Recovery, on which different injection schemes compared (water-flooding, gas injection, WAG and CO2 injection) for enhanced oil recovery for giant carbonate reservoirs in the Middle East.

Its purpose is to evaluate the effectiveness of CO2 injection into carbonate oilfields. The reservoir under consideration is a layered system (heterogeneous). The reservoir is divided into two sections: a lower zone of generally low permeability layers and an upper zone of high permeability layers inter-bedded with low permeability layers; the upper zone's average permeability is 10-100 times that of the lower zone.

The injected water tends to flow through the upper zone along the high permeability layers during water-flooding, with little or very slow cross-flow into the lower zone, resulting in a very poor sweep of the lower zone. There is a lot of scope for improvement in oil recovery from heterogeneous mixed-wet carbonate reservoirs. The apparent impediment to water

[1]: Simeon Agada and Sebastian Geiger, wettability, Trapping and Fracture-Matrix Interaction during WAG Injection in Fractured Carbonate Reservoirs, SPE-169054-MS, p2.

invading the bottom strata suggests that a miscible fluid could be injected into the lower zone.

It performed a series of core-flood experiments to investigate the performance of various displacement procedures, including water-flooding, hydrocarbon gas flooding, water-alternative-gas (WAG), and CO2 injection. Due to the development of miscibility between CO2 and oil, it shows that the local displacement efficiency for CO2 flooding is around 97% - substantially higher than that obtained through water-flooding or hydrocarbon gas injection. In contrast, natural gas injection is not a miscible process and recovers less oil. In all cases though, gas injection recovers additional oil after water-flooding.[1]

It shows that the CO2 injection shows a great potential to improve the oil recovery.

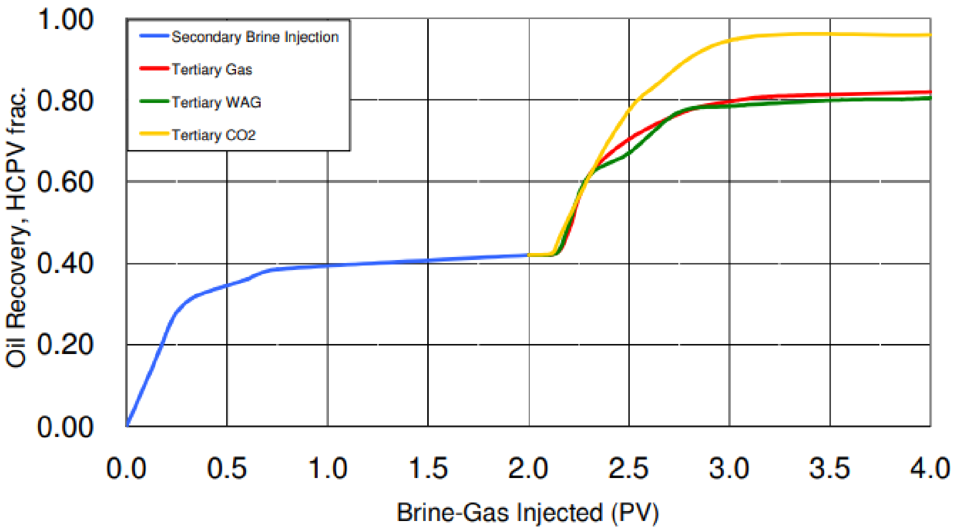


Figure 3.1: Comparison of WAG, gas and CO2 injection recoveries (Saif S. Al Sayari, 2009)

3.2. Comparison of CO2 injection vs. chemical injection (Alkaline-Surfactant-Polymer):

To achieve the same purpose as the previous mention, another comparative study was done by Simon Roussanaly and Alv-Arne Grimstad, titled the economic value of CO2 for EOR applications. It is considered that to accessthe CO2 EOR and chemical for Alkaline-Surfactant-polymer (ASP) EOR options. For both technologies, three scenarios (high, medium and low) are built to represent a range of possible responses of the oil field to the EOR methods considered. The general shape of the additional oil production profile for both CO2 EOR and chemical EOR is characterized by an initial delay after the start of the EOR

[1]: Saif S. Al Sayari, the Influence of Wettability and Carbon Dioxide Injection on Hydrocarbon Recovery, Imperial College London SW7 2AZ, p 177.

operation. Which initial delay is assumed to be longer for chemical EOR due to the more favorable mobility ratio of the injected fluids and the corresponding longer time for a breakthrough.

We can observe that the three scenarios of CO2 recovered the highest EOR production annually, on which, for the first five years, it recovered about 11, 9 and 6.5 Mbbl/y for high, medium and low scenarios, respectively. Furthermore, it recovered for the chemical flooding about 7, 5 and 3 Mbbl/y for high, medium and low scenarios, respectively. [1]

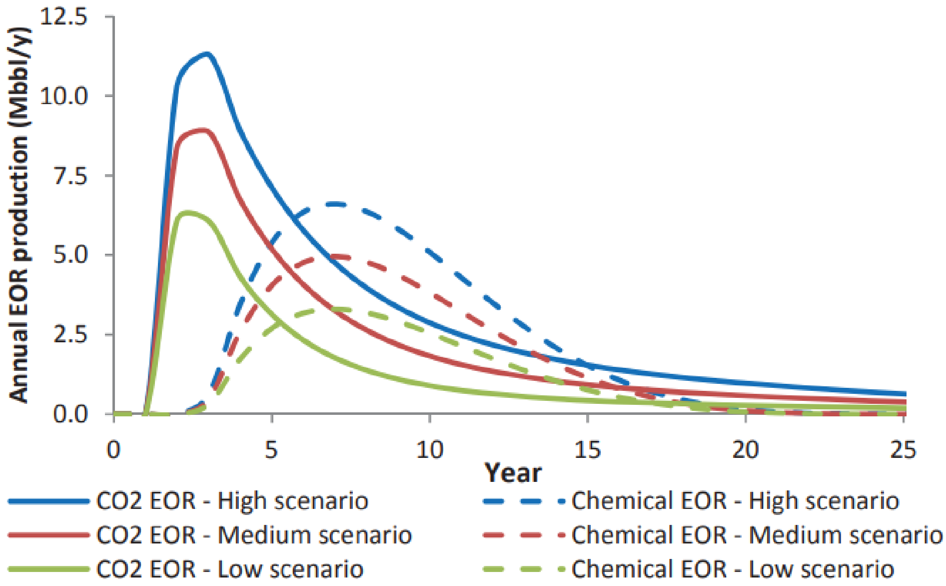


Figure 3.2: Annual EOR oil production scenarios for the two EOR methods and the three production scenarios, (Simon Roussanaly, and Alv-Arne Grimstad, 2014).

3.3. Discussion:

After analyzing the comparative studies of the different EOR techniques to improve oil recovery, we highly say that the CO2 injection as an EOR mode is highly effective in improving the ultimate oil recovery compared to other EOR methods.

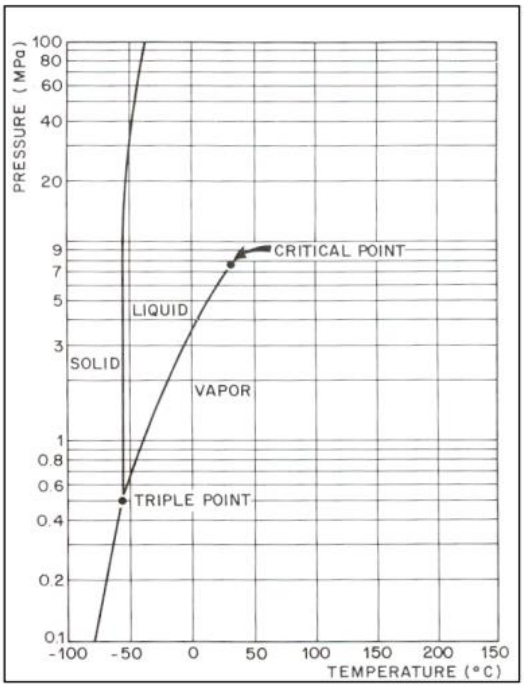
[1]: Simon Roussanaly, and Alv-Arne Grimstad, The economic value of CO2 for EOR applications, Energy Procedia 63 (2014) 7836 – 7843, p 3-4.

Chapter VI:

CO_2 injection on the Naturally Fractured Reservoirs.

1. **Introduction:**

CO_2 injection as an EOR method shows great potential for improving oil recovery due to its miscibility property with oil. The new studies are searching for applications in naturally fractured reservoirs. To completely understand CO_2-EOR flooding, it is necessary first to grasp the properties of CO_2 and the principles of the CO_2-EOR process. CO_2 is a colorless, odorless gas that is about 1.5 times heavier than air at room temperature. CO_2 is 2-10 times more soluble in oil than water. CO_2 raises water viscosity and produces carbonate acid, favoring shale and carbonate rocks. Above critical pressures and temperatures, CO_2 is in the supercritical state. It forms a phase whose density is close to a liquid's, even though its viscosity remains low (0.05–0.08 cp). This dense CO_2 phase can more easily extract hydrocarbon components from oil than gaseous CO_2. [1]



The properties under standard condition at 1.013 bar and 0 °C are:

- Mol. weight: 44.010 g/mol
- Sp. gravity to air: 1.529
- Density: 1.95 kg/m^3

Critical properties:

- Tc: 31,05 °C
- Pc: 73.9 bar
- Vc: 94 cm^3/mol

Triple point:

- Ttr: - 56,6 °C
- Ptr: 5.10 bar

Figure 4.1: CO_2 phase diagram.[2] (Odd Magne Mathiassen, 2003)

2. **CO2 Miscibility:**

From a fundamental point of view, CO_2-EOR works on a very simple principle, namely, that given the right physical conditions, CO_2 will mix miscible with oil, acting much like a

[1] : Abdelaziz Nasr El-hoshoudy and Saad Desouky, CO2 Miscible flooding for enhanced oil recovery, Intechopen, p 4-5.
[2] : Odd Magne Mathiassen, CO2 as Injection Gas for Enhanced Oil Recovery and Estimation of the Potential on the Norwegian Continental Shelf, NTNU, p 6.

thinning agent, much the same way that gasoline does with motor oil. After miscible mixing, the fluid is displaced by chase phase, typically water**.**

In more scientific terminology, Holm 19 describes miscibility as: "the ability of to form a single homogeneous phase when mixed in all two or more substances proportions. For petroleum reservoirs, miscibility is defined as that physical condition between two or more fluids that will permit them to mix in all proportions without the existence of an interface. If two fluid phases form after some amount of one fluid is added to others, the fluids are considered immiscible."

Technically, the critical consideration is that in miscible displacements the residual oil saturation, that is, the oil left after being miscible contacted with CO2, is reduced nearly to zero. This leads to high oil recoveries and favourable project economics. This is in distinction to immiscible displacements where considerable residual oil saturations can remain, often leading to unfavourable project economics. Flooding a reservoir with CO2 can occur either miscible or immiscibly.[1]

Depending on reservoir pressure, temperature, and oil properties, the injected CO2 may become miscible or remain immiscible with the oil. The miscible CO2-EOR method often achieves better recoveries than the preferred immiscible approach.

2.1.<u>Minimum Miscibility Pressure (MMP) determination:</u>

The most common method used to determine the conditions at which miscible displacement is achieved is known as a slim tube experiment. A long (40-80 ft), small diameter (1/4 in), high-pressure tube is packed with clean sand (or glass beads) to achieve a fluid permeability of 3 to 5 Darcie's.The minimum miscibility pressure (MMP) is the pressure at which miscibility occurs. The MMP was established by Holm and Josendal (1974) as the pressure at which more than 80% of oil-in-place (OIP) is recovered at CO2 breakthrough. Although, more recently, an oil recovery of at least 90% at 1.2 hydrocarbon pore volume (HCPV) of injected CO2 is frequently used as a rule of thumb for determining MMP (Yellig& Metcalfe, 1980), Oil recovery increases rapidly with increasing pressure, then flattens out when MMP is reached, as shown in the figure below.[2]

[1] : http://www.ingenieriadepetroleo.com/miscibility-co2-enhanced-oil-recovery/, seen on 20/05/2023 at 18 pm.

[2] : Mahendra K. Verma , Fundamentals of Carbon Dioxide-Enhanced Oil Recovery (CO2-EOR)—A Supporting Document of the Assessment Methodology for Hydrocarbon Recovery Using CO2-EOR Associated with Carbon Sequestration, U.S. Department of the Interior, Report 2015–1071, p 11.

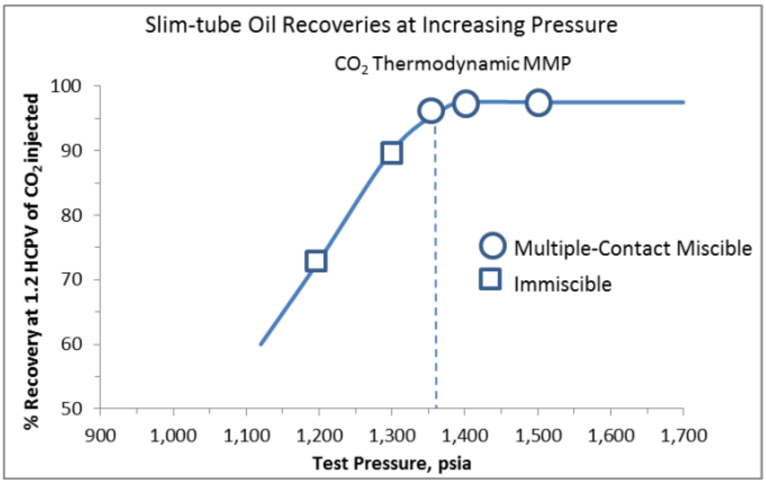


Figure 4.2: Slim-tube oil recoveries at increasing pressures for fixed oil composition and temperatures CO2, carbon dioxide; psia, pounds per square inch absolute; %, percent.(Mahendra K. Verma, 2015).

There are three types of miscible hydrocarbon mechanisms: (1) first contact; (2) vaporizing gas drive, also known as high-pressure gas drive; and (3) condensing gas drive, sometimes called enriched gas drive.

- First-contact miscible (FCM) solvents mix with reservoir oil in all proportions, and the mixture remains in one phase. Other solvents, like CO2, are not miscible on the first contact, but they do develop miscibility on multiple contacts, known as dynamic miscibility, resulting in much-improved oil recovery.
- The vaporizing gas-drive process achieves dynamic miscibility by in situ vaporization of the intermediate-molecular-weight hydrocarbons from the reservoir oil into the injected gas, or CO2.
- The condensing gas-drive process achieves dynamic miscibility by in situ transfer of intermediate-molecular-weight hydrocarbons (or CO2 in the case of CO2-EOR) into the reservoir oil.

When the reservoir pressure is above the MMP, miscibility between CO2 and reservoir oil is achieved with time as displacement occurs in what is classified as multiple-contact or dynamic miscibility. The intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO2 (vaporization gas-drive process), and part of the injected CO2 dissolves into the oil (condensation gas-drive process) (Merchant, 2010). [1]

[1] : Previous reference, p 11.

This mass transfer between the oil and CO2 makes the two phases miscible without any interface. It helps to develop a transition zone (Jarrell and others, 2002) that is miscible with oil in the front and CO2 in the back.

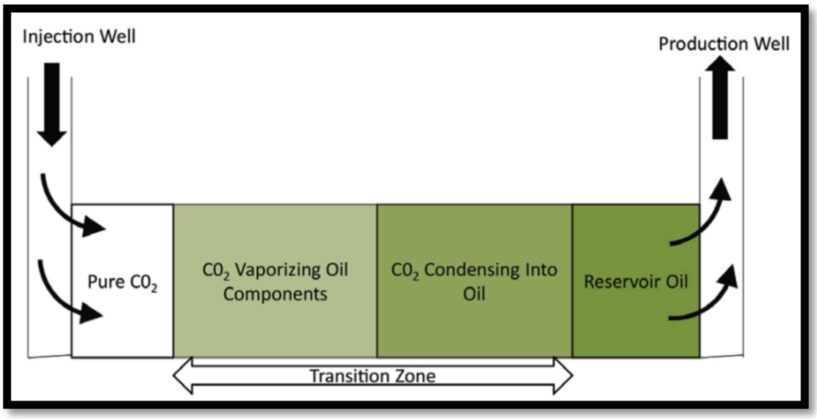


Figure 4.3: The schematic of the CO2 (carbon dioxide) miscible process showing the transition zone between the injection and production well, (Mahendra K. Verma, 2015.)

Slim-tube tests performed in a laboratory to determine MMP are more reliable than mathematical models or correlations. Due to the high cost of slim-tube testing, mathematical models and correlations are two more methods for estimating MMP.

Mathematical models outperform correlations regarding results, utilize equilibrium data and an equation-of-state (EOS), and offer a more rigorous approach to computing MMP. Correlations are simple to apply but have limits and should only be used in the absence of slim-tube tests or mathematical models. [1]

3. Comparison of applying CO2 injection (Continuous versus. Huff and Puff):

3.1. Injection design:

For the CO2-EOR process, the CO2 can be injected as:

I. Continuous CO2 injection: This process requires continuous injection of a predetermined volume of CO2 with no other fluid. Sometimes a lighter gas, such as nitrogen, follows CO2 injection to maximize gravity segregation. This approach is implemented after primary recovery and is generally suitable for gravity drainage of reservoirs with medium to light oil and reservoirs strongly water-wet or sensitive to water-flooding.

[1] : Previous reference, p 12.

II. <u>Continuous CO2 injection followed with water:</u> This process is the same as the continuous CO2 injection process except for chase water that follows the total injected CO2 slug volume. This process works well in reservoirs of low permeability or moderately homogenous reservoirs.

III. <u>Conventional water-alternating-gas (WAG) followed with water:</u> In this process, a predetermined volume of CO2 is injected in cycles alternating with equal volumes of water. The water alternating with CO2 injection helps overcome the gas override and reduces the CO2 channeling, thereby improving overall CO2 sweep efficiency. This process is suitable for most reservoirs with permeability contrasts among various layers.

IV. <u>Tapered Water-Alternating-Gas:</u> This design is similar in concept to the conventional WAG but with a gradual reduction in the injected CO2 volume relative to the water volume. To improve CO2 utilization, tapered WAG is the method most widely used today because this design enhances the efficiency of the flood and prevents early breakthrough of the CO2, thus less recycled CO2 and better oil recoveries. The CO2 utilization is the volume of CO2 used to produce a barrel of oil and is reported either as a gross volume, including the recycled CO2, or a net volume.

V. <u>Water-Alternating-Gas followed with gas</u>: This process is a conventional WAG process followed by a chase of less expensive gas (for example, air or nitrogen) after the total CO2 slug volume has been injected.[1]

There are two modes of gas injection for the simulation studies. One is the continuous flooding, whereby injector wells serve to inject the gas, and others serve as the producer. The other technique is the Huff and Puff injection technique, which has shown far superior results. A well is initially injected with the gas for some period of time. After that, the well is shut, and soaking time is provided for the gas to reach and mix with all parts of the reservoir. Thereby then, the well is put into production.

3.2.<u>Procedure:</u>

In order to compare the effective CO2 injection design to improve the recovery factor on the NFR, an experiment study was done in China by Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, on "Experimental Study on CO2-EOR in Fractured Reservoirs: Influence of Fracture density, miscibility and Production Scheme.

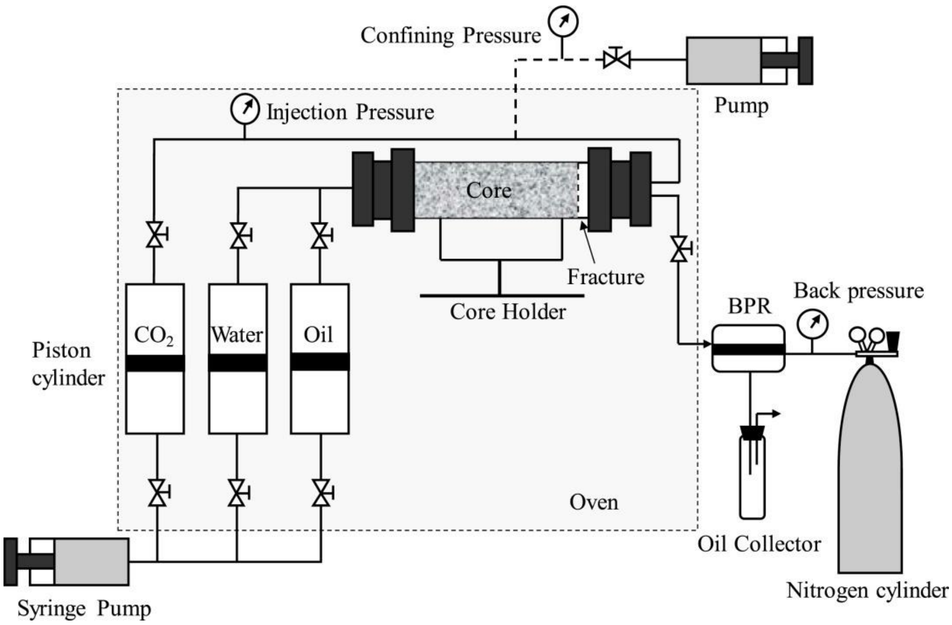
[1] : Abdelaziz Nasr El-hoshoudy and Saad Desouky, CO2 Miscible flooding for enhanced oil recovery, Intechopen, p 5.

The cores were weighted, vacuumed, and flushed with water before conducting CO2 injection experiments, and the wet cores were weighted again. Core pore volume and porosity were calculated. The cores were then flooded with water until a steady state condition was attained; at this point, the flow rate and pressure difference between the core holder inlet and outlet lines were measured. Darcy's equation was used to calculate core permeability. The cores were completely soaked with water before being flooded with crude oil or tetradecane at 60 ^oC until no water was produced. The amount of water replaced by cured oil or tetradecane in the generated water was measured, and the connate water saturation and initial oil saturation were determined. Upon the establishment of initial oil saturation, a process of aging which left the cores untouched for 24 h at 60 ^oC 180 ^oC to reach a proper equilibrium condition was applied. The CO2 flooding process in the matrix-fracture system was started after the cores were prepared. The Back Pressure regulator (BPR) was employed to maintain a constant core pressure during gas injection. The confining pressure was constantly maintained at 3.0 MPa above the core pressure. CO2 was gradually pumped into the core holder using a syringe pump until the pressure inside the core holder reached the required level, and the gas primarily flowed via the fracture due to the high permeability contrast between fracture and matrix. Then that, CO2 was injected at a constant volumetric flow rate of 0.1 cm^3/min.

The produced oil was collected from the output, and its volume was recorded every 2 hours to calculate the oil recovery factor (RF). The flooding process was repeated until no more oil was produced. All of the experiments were carried out at 60 ^0C. We chose crude oil as the oil phase and set the testing pressures at 17.5 MPa and 25.0 MPa, respectively, to achieve immiscibility (IM) and multi-contact miscibility (MCM) conditions. Furthermore, we used tetradecane as the oil phase and set the testing pressure to 25.0 MPa to achieve first-contact miscibility (FCM). It should be noted that all of the experimental protocols used to perform CO2 flooding tests under 0 fracture-density conditions were identical as those discussed above, except that CO2 was directly injected into the matrix utilizing input-2. Following the aforementioned approach, CO2 huff-and-puff (HnP) experiments were carried out following CO2 flooding to further reduce the residual oil saturation in the matrix. The input-1 and output valves were closed, and the system was turned off for 2 hours to soak. [1]

[1] : Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, Experimental study on CO2-EOR in fractured reservoirs: Influence of fracture density, miscibility and production scheme, PETROL 5511, p 9.

The interaction between CO2 and oil occurred during this time period. The BRP was then adjusted to a predetermined pressure with a nitrogen cylinder, and the output valve was opened to allow oil and CO2 production until the core pressure was depleted to this pressure (puff cycle). Each cycle's produced oil was collected in the oil collector, its amount was recorded, and the recovery factor was determined. Then that, CO2 was pumped into the core holder at a constant injection rate of 10.0 cm^3 /min until the core pressure reached the predetermined operating pressure (17.5 MPa or 25.0 MPa). The preceding procedure represents a complete huff-and-puff cycle for a given operating pressure. The following cycle was performed using the same approach at the same operating pressure and repeated until the incremental recovery factor (IRF) was less than 1.0% (Qazvini et al., 2014), which is known as a multi-cycle operation. [1]



<u>Figure 4.4</u>: Schematic illustration of CO2 injection apparatus. (Mingchen Ding, Miao Gao, Yefei Wang, ZhengtianQu, Xu Chen, 2018).

3.3.<u>Results and conclusions:</u>

After conducting the experiment procedure by them, the results are shown below:

<u>a.</u> In fractured reservoirs, increased fracture density contributes an additional recovery factor. However, fractures drastically affect the displacement effectiveness of CO2 flooding; indicating that fracture density positively affects CO2 flooding. However, it has

[1]: Previous reference, p 10.

a negative effect on the CO2 Huff-and-Puff (HnP). However, for the heavy oil reservoirs, the First-Contact-Miscibility (FCM) conditions are unachievable, indicating the change of the oil phase in the experiment; for the heavy oil reservoirs, the Multi-Contact-Miscibility (MCM) conditions recover the maximum of Recovery Factor (RF) (47.2%); furthermore, for the light/medium oil reservoirs, the FCM conditions recover the maximum of RF (68.1%).Taking into consideration that the Minimum Miscibility Pressure (MMP) for the oil/CO2 is 17.8 at 60 ^{0}C and the MMP for the tetradecane/CO2 is 12.35 at 60 ^{0}C (it achieves 17.8 at 90 ^{0}C). As all the results are shown in Table 6, a summary of CO2 flooding and HnP results.

- **Comparison CO2 injection flooding vs. Huff-n-Puff**: we can observe from the results that:

- For the crude oil and immiscible (IM), and MCM conditions, we can see that the HnP recover the highest RF more than the flooding injection with the increasing of the fractured density; it recovers about 45.1%, 40.9% and 30.8% for IM conditions and about 71.3%, 66% and 38.7% for MCM conditions of fracture density of 2.5, 5 and 8.3 fracture par meters respectively.

- For tetradecane and FCM conditions, we can see that the HnP recovered the highest RF for 2.5 of fracture density more than the flooding, about 48.7% RF for HnP and 22.1% for flooding injection; however, with the increasing fracture density of 5 and 8.3, the flooding injection recovers the highest RF about 48% and 68.1% more than the RF that recovered by the HnP injection about 25.8% and 6.3% respectively.

b. The color and composition changes of produced oil during the CO2 flooding process in a matrix-fracture system indicate that the main oil recovery mechanism in fractured reservoirs is oil swelling at the beginning of CO2 injection and gradually shifts to the extraction of light and intermediate components (C5-C30) by CO2 with increased time of gas injection, which indicates that after achieving the miscibility the CO2 dissolves on the oil by reducing its viscosity, reducing the tension interfacial that helping the displacement of the oil.

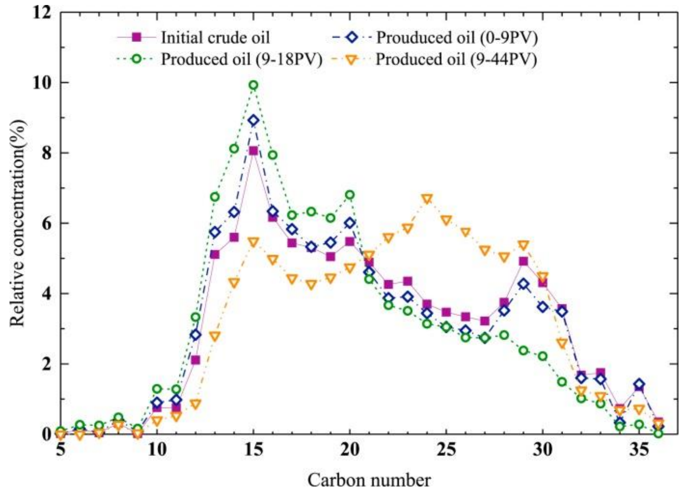


Figure 4.5: Compositional analysis results of the produced oil collected at different injection periods with various times of CO_2 injection, (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

c. At the same fracture-density condition, CO_2 flooding in the FCM regime performed better than the MCM and IM regimes. Furthermore, FCM CO_2 flooding is viable for improving oil recovery at high fracture density; it is recovery factor of 68.0% (equal to or than 5.0 fractures per meter).

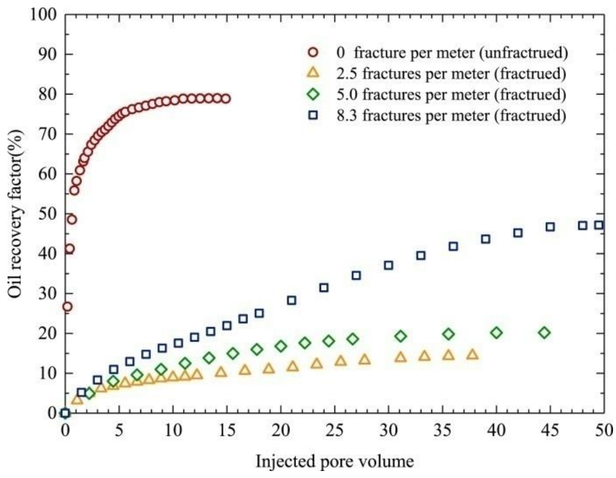


Figure 4.6: Oil recovery factor vs. CO_2 injection time during MCM flooding process at different fracture-density conditions. (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

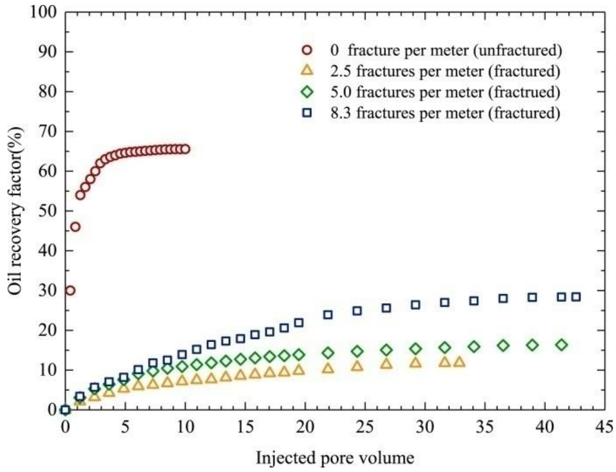


Figure 4.7: Oil recovery factor vs. CO2 injection time during IM flooding process at different fracture-density conditions (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

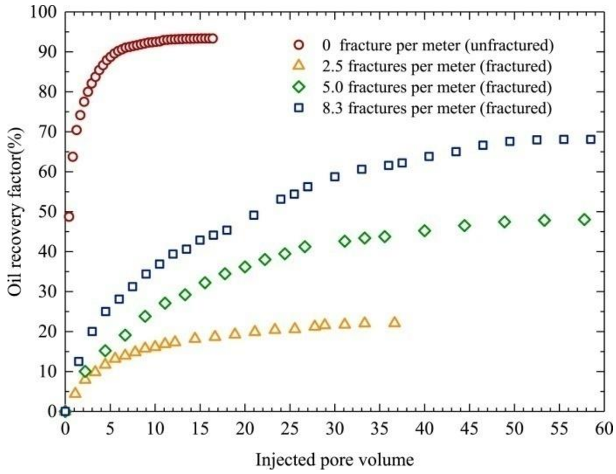


Figure 4.8: Oil recovery factor vs. CO2 injection time during FCM process at different fracture-density conditions. (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

d. For CO2 flooding, at low fracture density conditions, the CO2 floods in all miscibility regimes are ineffective because of poor sweep efficiency. However, at high fracture-density conditions, the FCM and MCM are more favorable, but under the FCM conditions recover, the maximum RF of about 68.1% of OIPP.

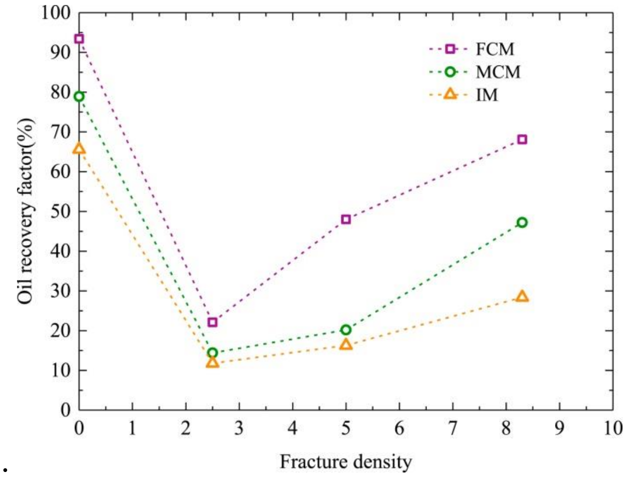


Figure 4.9: Ultimate oil recovery factors of CO2 flooding under different miscible conditions (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

e. Under IM, MCM, and FCM conditions, CO2 HnP can recover a significant portion of the oil from the matrix that has undergone CO2 flooding testing, demonstrating that CO2 HnP has a considerable advantage over flooding in fractured reservoirs. It recovers the highest recovery factor for the lowest fracture density and for the MCM condition RF of 71.3% OOIP.

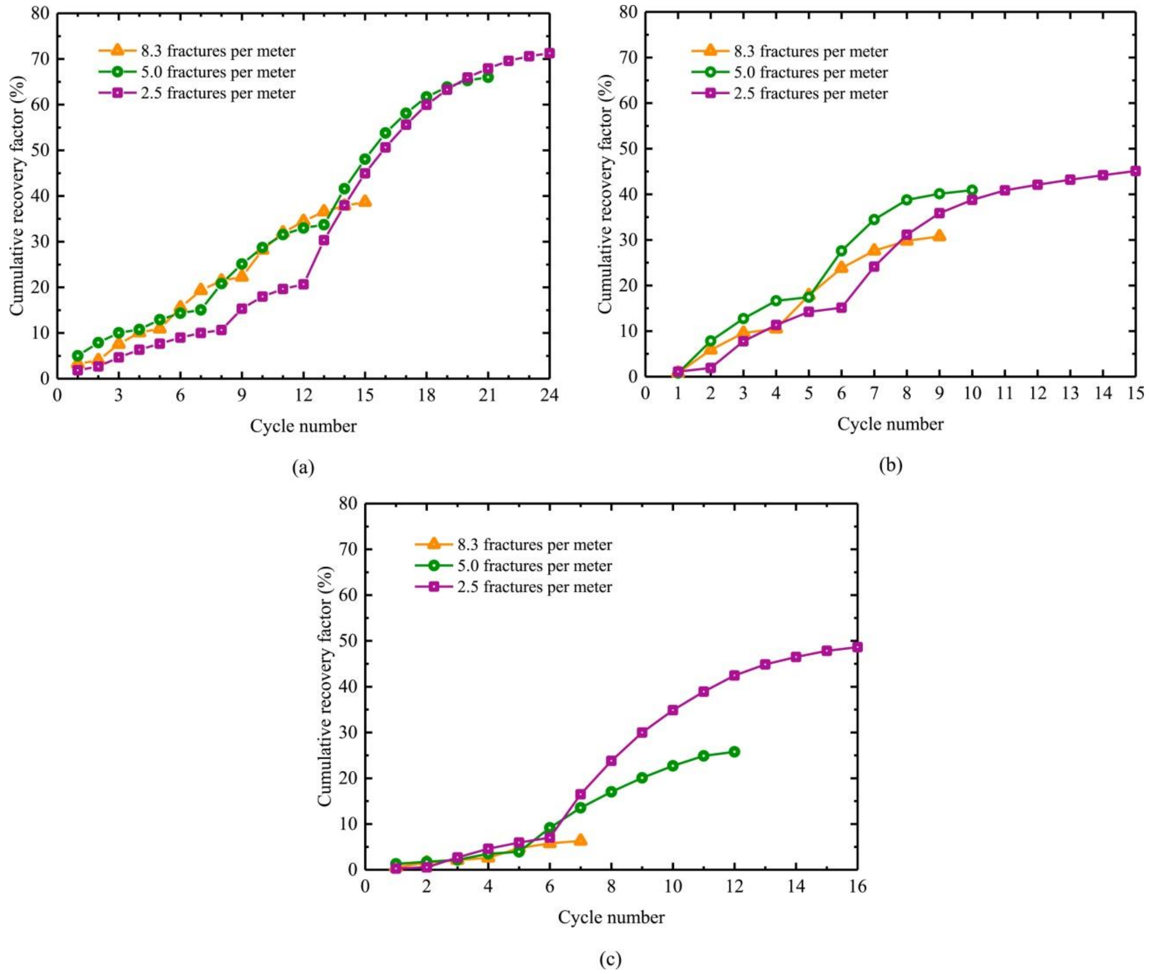
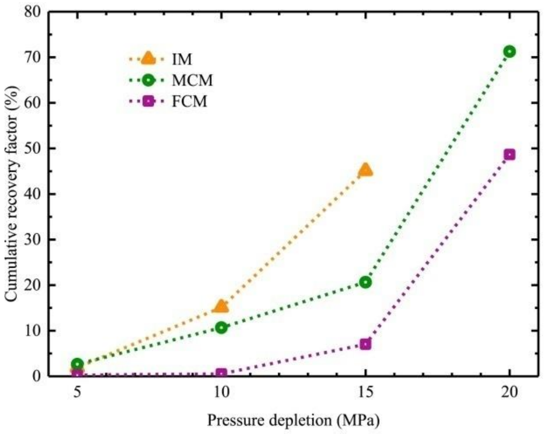
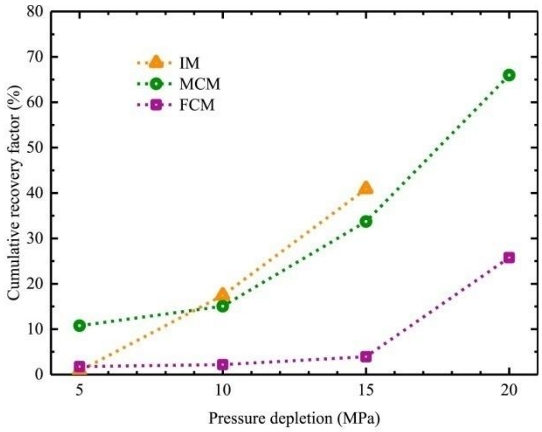


Figure 4.10: Cumulative recovery factors from matrix-fracture system vs. cycle number during CO2 HnP process conducted at different fracture-density conditions and under: **(a)** MCM condition; **(b)** IM condition; **(c)** FCM condition. (Mingchen Ding, Miao Gao, Yefei Wang, Zhengtian Qu, Xu Chen, 2018)

f. Higher pressure depletion during the puff cycle is more favorable for the CO2 HnP scenario, which obtains the maximum recovery factor at the MCM condition (71.3%), whose recovery efficiency is even higher than that at the FCM condition for low fracture density conditions.



(a)



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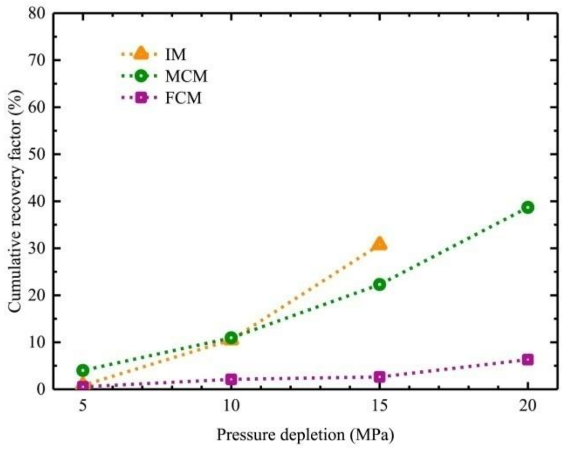

(c)

Figure 4.11: Cumulative recovery factors of CO2 HnP versus pressure depletion under three miscibility conditions from matrix-fracture system with the fracture density of: (a) 2.5 fractures per meter; (b) 5.0 fractures per meter; (c) 8.3 fractures per meter, (Mingchen Ding, Miao Gao, Yefei Wang, ZhengtianQu, Xu Chen, 2018)

General Conclusion and Recommendations

Naturally fractured reservoirs are important contributors to global petroleum reserves and production. These reservoirs are characterized by dual porous mediums: fracture network and matrix. It is complex to determine the proper EOR technique to apply due to the complexity of the fluid behavior on these reservoirs. The new studies indicate that CO2 injection under supercritical conditions has excellent potential to improve oil recovery technically and economically.

The following main conclusions can be drawn based on the analyses of the results presented in our project:

CO2 injection is more practical and efficient than other EOR methods to improve the oil recovery for the NFRs; the huff-and-puff injection mode is more effective than gas flooding. In other words, the huff-and-puff gas injection may have the highest liquid oil production potential in these reservoirs.

However, it is efficient for the IM and MCM conditions; furthermore, the flooding injection mode is more efficient for FCM conditions.

The flooding injection is more efficient for highly fractured reservoirs (equal to or greater than five fractures per meter) to enhance the oil recovery factor; however, the HnP injection mode is more efficient for low fractured reservoirs.

The main limitation that can be faced in applying the CO2 injection as an EOR mode is how to generate it or the source of it.

In order to apply the CO2 injection on the naturally fractured reservoirs in Algeria, it should have a clear understanding of the NFR behavior and the ability to model these reservoirs in 3D modeling, especially the fracture network

- **Recommendations:**

Based on the analysis of the results shown earlier, we recommend:

1. For highly fracture density reservoirs (equal or greater than 5 fractures per meter), the CO2 flooding injection is more favorable to improve the recovery factor, it is recover about 48.0% of RF.
2. For low fracture density reservoirs, the CO2 HnP is more favorable to improve the recovery factor; it is recover about 71.3% of RF.

3. For the miscibility conditions, the FCM conditions are the more favorable condition for the CO_2 injection flooding to improve the oil production (68.1% RF); however, the MCM conditions are for the HnP injection (71.3% RF).

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