Enhance oil recovery using CO_2 Injection

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June 2021

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A thesis submitted in partial fulfilment of the requirements for the degree of

Petroleum Engineering

Department of Natural Resources Engineering and Management

School of Engineering

University of Kurdistan Hewlêr

Degree of PE

June 2021

Erbil, Kurdistan

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Dedication

This thesis is dedicated to my supporting surroundings for their continuous help and support towards me.

Soma Imran
2021

Acknowledgements

First and foremost, I am really gratefully for Dr. Maha Hamoudi constant support and guide throughout this thesis paper. It was a great pleasure to have Dr. Maha as my supervisor and it was a great privilege to work and learn from Dr. Maha. I also want to express my gratitude for Mr. Ararat Abdolla for guiding me on how to use the software and help me in the process of using the software. Once again, I am really thankful for the continuous support and advice throughout this year for me to be able to work on and finish this thesis, with their constant enrichment and supervising I was able to complete and enrich my thesis. I want to thank DNO for supporting this paper by providing the required data.

I want to thank my family and friends for their continuous support and encouragement for me to be able to come this far.

Abstract

Hydrocarbon production is divided into three stages according to the production method used and time; primary oil recovery, secondary oil recovery, tertiary/enhance oil recovery. In order to produce the remaining oil in place different methods are used in the secondary and enhance oil recovery. In this paper, carbon dioxide flooding will be used. Carbon dioxide injection is one of the most common solvent methods used, mainly in the USA. Carbon dioxide injection leads to reduction in the oil viscosity and interfacial tension, which leads to better mobility ratio and displacement. In this paper, to evaluate the oil recovery using miscible CO_2 injection EORgui software was used. Screening criteria was done to investigate, which displacement method is suitable for the reservoir data used. The reservoir data used was from a reservoir from Kurdistan region, operated by DNO. The results show that miscible CO_2 injection was leading with 78% in first place. Therefore, miscible WAG-CO_2 was injected into the well. The results showed that oil recovery increases as miscible CO_2 is injected into the reservoir but as the method is changed to water injection the oil recovery is less. However, the overall recovery factor was 43.22%. Sensitivity analysis was also done to determine the effect of total fluid injection rate on oil recovery using three different injection rates. The results determined that as the injection rate increases the oil production rate increase and the breakthrough time is earlier. The highest oil recovery factor was determined using 3000 rb/d injection rate.

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List of Abbreviations

Abbreviations	Full Description
API	American Petroleum Institute
CCS	Carbon Capture Storage
CO2	Carbon Dioxide
CT-scan	Computed Tomography scan
EOR	Enhanced Oil Recovery
EVGSAU	East Vacuum Grayburg San Andres Unit
FCM	First Contact Miscibility
GOR	Gas-Oil Ratio
GSGI	Gravity Stable Gas Injection
HCPV	Hydrocarbon Pore Volume
IEA	International Energy Agency
IFT	Interfacial Tension
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MCM	Multiple Contact Miscibility
MMP	Minimum Miscibility Pressure
MMPa	Average Minimum Miscibility Pressure
MMSTB	Million Stock Tank Barrels
MPa	Mega-Pascal
OIP	Oil in Place
OLGA	Oil and Gas Simulator
OOIP	Original Oil in Place
PV	Pore Volume
PVI	Pore Volume Injected
RBS	Rising Bubble Apparatus
ROZ	Residual Oil Zone
SACROC	Scurry Area Canyon Reef Operators Committee
TWAG	Tapered Water Alternating Gas
WAG	Water Alternating Gas

Chapter 1 - Introduction

Oil production is divided into three phases depending on the production method and the time of the production. In the early life of the reservoir life depending on the strength of the natural drive mechanism of the reservoir. The main types of drive mechanisms of primary oil recovery are gas-cap drive, water drive, depletion drive, and gravity drainage. However, the recovery factor of the primary oil recovery is low and is not capable of producing most of the oil in place in the reservoir. As a result, secondary oil recovery is used by means of artificial lift or injection of fluids present in the reservoir, such as immiscible gas and water injection, to improve the oil recovery by recovering the movable oil left behind during primary oil recovery and maintain the reservoir pressure **(Latil, 1980: Lake, 2010: Bavière, 1991).** Nevertheless, two-thirds of the oil in place will still not be produced using secondary recovery and some parts of the reservoir will remain unswept due to high viscosity of oil, rock heterogeneity, and poor microscopic displacement efficiency. Therefore, through tertiary oil recovery, injection of external agents to reservoir, the displacement efficiency and the sweep efficiency are improved to be able to get higher recovery factor **(Bavière, 1991).** Tertiary oil recovery is sometimes identified as enhanced oil recovery also, if the phases are not effective to be applied and then tertiary oil recovery is applied directly but it is called enhanced oil recovery in this case. Therefore, enhance oil recovery is not restricted to any particular mode of the reservoir life and can be applied at any phase **(Lake, 2010: Bavière, 1991).** As the demand for oil increase, more enhanced oil recovery methods are developed and improved throughout the years and still continuous studies and experiments are done to understand the mechanism to improve enhance oil recovery **(Bavière, 1991).** As result, enhanced oil recovery is categorized into three main types solvent, chemical, and thermal **(Lake, 2010).** Solvent flooding, especially using CO_2, has been gaining attention over the years **(Lake, Lotfollahi, & Bryant, 2019).**

Solvent/miscible flooding is injecting hydrocarbon or non-hydrocarbon components into the reservoir in order to mix with the oil to be displaced **(Lake, 2010: Alvarado & Manrique, 2010: Sheng, 2013).** The mass transfer between the injected fluid and the oil phase under high pressure flooding increases as miscibility is achieved between the injected fluid and oil causing the interfacial tension between the two fluids to reduce **(Sheng, 2013: Bavière, 1991).** Since for immiscible recovery methods, oil is trapped due to capillary forces and their displacement efficiency is generally low **(Green & Willhite, 1998),** so miscible flooding is used to reduce residual oil trapped by capillary forces **(Sheng, 2013)**. The mechanism drives behind oil recovery using solvent flooding is through vaporization, solubilization, condensation, reduction of oil viscosity, oil swelling and solution gas drive **(Lake, 2010)**. The injected fluid is characterized into hydrocarbon or non-hydrocarbon components, some examples for latter are nitrogen, carbon dioxide, and hydrogen sulfide are used **(Sheng, 2013)**. Moreover, some other injection fluids used for miscible floods are condensed petroleum gas (LPG), natural gas, liquefied natural gas (LNG), exhaust gas, flue gas, organic alcohols, etc. **(Lake, 2010).**

It always has been a concern to find solution for global warming and climate change with the increase in greenhouse gases such as carbon dioxide, methane, nitrous oxide, and ozone since the beginning of the industrial revolution **(Sheng, 2013: Fath & Pouranfard, 2014)**. In the US the largest greenhouse gas emission is carbon dioxide by 81%, while methane and nitrous oxide are 10% and 7% respectively **(US Greenhouse Gas Inventory Report, 2018).** Although Iraq is only responsible for 0.6% of the global CO_2 emission, but the annual CO_2 emission in 2017 from fossil fuels and cement was reported to be 3.98 billion tones, which 137.43 million tons were produced from oil. Additionally, the greenhouse gas emission of Iraq per capita was 4.54 tones in 2016 **(Ritchie and Roser, 2017).** Carbon dioxide is used as an enhanced oil recovery method to obtain higher recovery factor about 7%-23% **(Moghadasi, Rostami, & Hemmati-Sarapardeh, 2018)**. Hence, this method can be used to improve recovery factor and environment at the same time **(Biyanto et al., 2017)**. Subsurface CO_2

storage is used to capture and store CO_2, and later used as injection fluid into reservoir to recover oil **(Biyanto et al., 2017).** In 1952 Atlantic Refining Company Dynes, Whorton, and Brownscombe were the first to be granted the patent for using CO_2-EOR method. Later in 1964 through a field test at Mead Strawn Field using CO_2 slug injection followed by carbonate water. The results showed that using CO_2 injection 53% to 82% more oil was recovered in compare to using water injection. This test was followed by more laboratory and pilot test, and the first commercial project using CO_2 as EOR method was in January 1972 at Scurry Area Canyon Reef Operators Committee (SACROC) Unit of Kelly-Snyder Field **(American Petroleum Institute, 2007)**. USA leads in the number of CO_2-EOR projects and oil production using CO_2 EOR, with more than 100 projects **(Lake et al., 2018)** and over 13,000 wells operation using CO_2 EOR **(Parker et al, 2009).** In fact, DNO began operation of the first Gas Capture and Injection Project in Kurdistan in 2020 **(DNO ASA, 2020)**. The gas flaring reduced by 75% at Peshkbir field, the gas was treated and transported 80 kilometers by pipeline to the Tawke field, where it injected to be stored and recharge the reservoir pressure. However, every method has its own advantage and disadvantages, the availability of CO_2 and operational cost are the disadvantages, such as high cost of CO_2, CO_2 injection cost which depends on the pressure and flow rate of the injection, and CO_2 recycling/reinjection costs **(Masoud, 2015: Biyanto et al., 2017)**. Moreover, it is important to identify the source of CO_2, natural or anthropogenic, and the transportation during EOR screening studies to identify the feasibility of CO_2 method **(Alvarado, and Manrique, 2010)**.

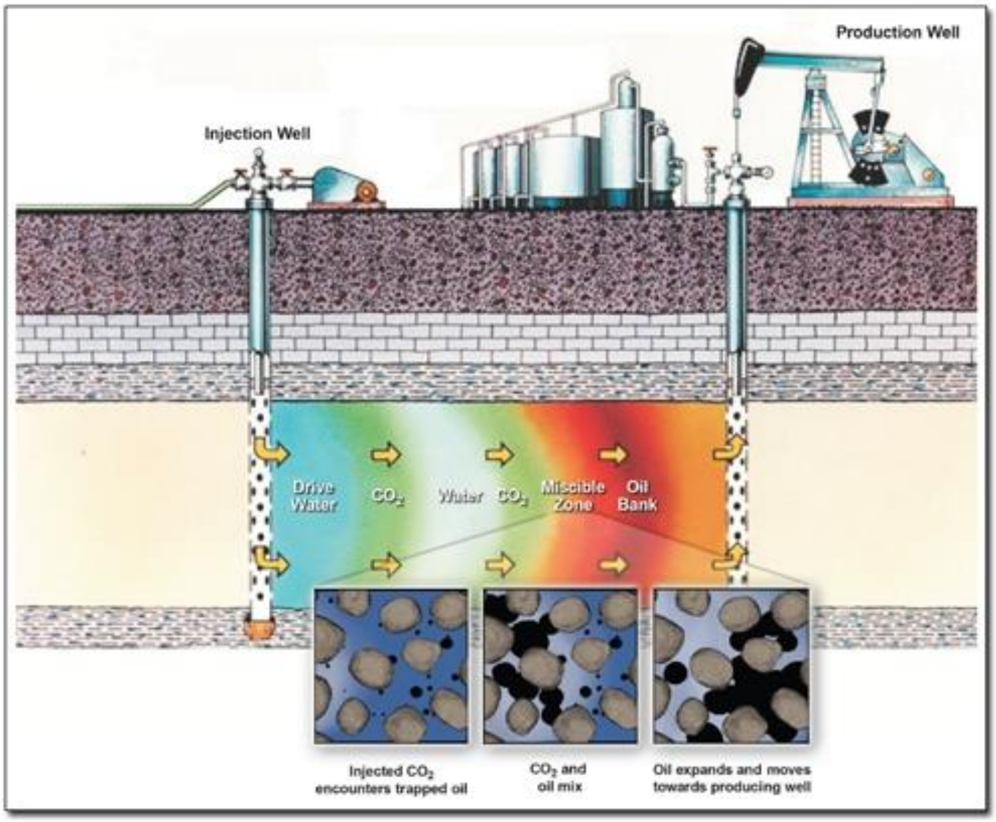


Figure 1-1 - WAG Injection using CO2 (National Energy Technology Laboratory, 2011)

1.1 - Problem statement

Various methods and technologies of enhanced oil recovery have been developed throughout the years and still continuous pilot and laboratory tests are conducted to improve the existing or develop new methods to improve the productivity of the reservoir. Although miscible injection using CO_2 has been receiving attention the past decade, not many projects on this method is found despite the favorable results obtained from the past projects and tests done. Miscible CO_2 injection has the potential to become one of the main methods with the increase in emission of CO_2 into the atmosphere and the consent concern of global warming. Therefore, it is important to study the mechanism behind miscible CO_2 injection and its effect on recovery, since both concerns about global warming and obtain an optimum recovery factor can be improved using this method.

1.2 - Objective

In this paper, enhanced oil recovery using miscible CO_2 will be evaluated using a EOR software called EORgui and the study will cover:

- Understand how miscible carbon dioxide improve the oil recovery
- Evaluate the effect of miscible carbon dioxide on improving the oil recovery on carbonates reservoirs.

1.3 – Thesis Organisation

In the upcoming first part, two chapters, of this paper the literature and background of the method is investigated and reviewed for better understanding of the method. For example, by going through pervious laboratory, simulation, and fields test are reviewed to understand the mechanism behind miscible CO_2-EOR flooding. In the second part of the paper, the simulation is done and discussed and compared with the pervious tests using miscible CO_2-EOR flooding.

Chapter 2 - Literature Review

CO_2 injection was first conducted during late 1950s and gained interest and attention throughout the years and with greenhouse gas emissions, mainly CO_2, increasing in the atmosphere projects using CO_2 injection also gained more spotlight. Since, it is being used as one of the solutions to reduce amount of CO_2 in atmosphere and used as gas flooding enhance oil recovery method **(Sheng, 2013: Fath & Pouranfard, 2014: Moghadasi, Rostami, & Hemmati-Sarapardeh, 2018: Biyanto et al., 2017: Jishun, Haishui, and Xiaolei, 2015)**. CO_2 injection is widely used in USA due to high percentage of CO_2 in the atmosphere and its production, especially due to the fossil fuel combustion **(Fath and Pouranfard, 2014).** In addition to using CO_2 as injection fluid, it is also captured from industrial facilities, fossil fuels plants, and other sources of CO_2 emission then it is stored in deep geological formation such as saline aquifers, depleted gas and oil fields, coal beds. This is called Carbon Capture Storage (CCS) and this is done to reduce the emission of CO_2 in the atmosphere **(Holloway, 1997: IPCC, 2005: Kertzer, Iglesias, and Einloft, 2012: Randi et al., 2017).** According to International Energy Agency, **IEA**, **(2019)** in 2017 the number of projects of CO_2-EOR was leading with 166 projects globally.

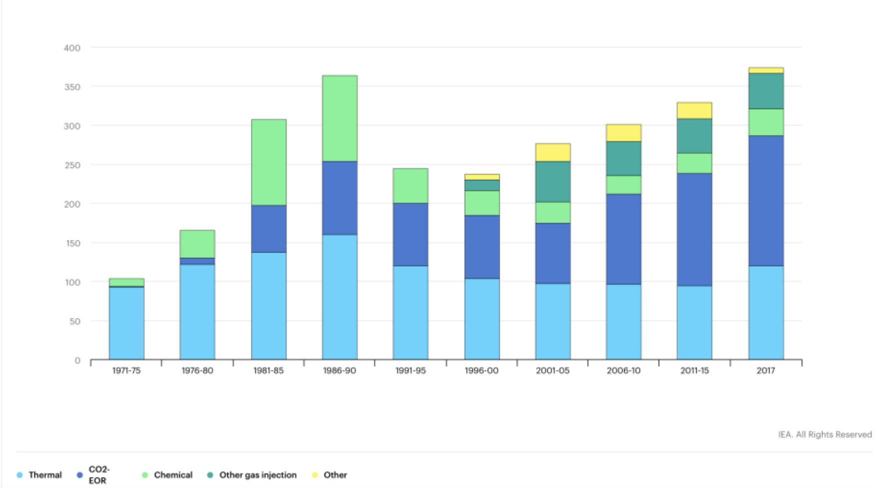


Figure 2.2-1 - EOR Projects (IEA, 2019)

Theoretically around 90% of oil can be recovered by CO_2-EOR. However, due factors such has complex reservoir lithology, structure, fractures, capillary pressure, rock wettability, oil viscosity, oil gravity, and permeability lower the recovery factor in reality **(Olea, 2017).**

In order to determine if a reservoir is suitable for CO_2 injection various complex numerical models are developed and evaluated to estimate the productivity and amount of CO_2 required **(Shaw, and Bachu, 2002)**. Therefore, **Shaw and Bachu (2002)** ranked and identified the most suitable sedimentary basins for CO_2 injection using analytical method, which was conducted on 8,637 oil reservoirs. Their screening was done oil reservoir were based on the oil gravity, reservoir temperature and pressure, minimum miscibility pressure, and remaining oil saturation. Then through the analytical method both the recoverable oil at the breakthrough and any fraction of hydrocarbon pore volume (HCPV) of the injection, and CO_2 sequestration storage capacity was calculated. The 4,470 reservoirs that passed the screening were characterized by: light oil within 27°-48°API, low reservoir temperature range of 31°C to 120°C, high initial reservoir pressure, ratio of reservoir pressure to MMP to be greater than 0.95, remaining oil saturation greater than 0.25, and low heterogeneity. The predication of oil recovery from Alberta's reservoirs calculation showed that at breakthrough 150×10^6 m^3, at injection of 50% HCPV 422×10^6 m^3, and at injection of 100% HCPV 558×10^6 m^3 would be produced. The recovered CO_2 after the breakthrough can be recycled by re-injecting it into the reservoir, which in their case was assumed to be 40% approximately so 127, 591, and 1,118 Mt of CO_2 will be captured and stored in the oil reservoir at breakthrough, 50% HCPV of injection, and 100% HCPV of injection, respectively.

Moreover, CO_2 is mostly implemented in projects of EOR in compare to the other miscible gas in the US due their abundant resources and a few projects are done other countries such as Turkey, Canada, and Trinidad, but in other countries other gases are used **(Xu et al., 2020).** In compare to N_2, CO_2 requires lower miscible pressure with crude oil, so can be used in both immiscible and miscible flooding **(Xu et al., 2020).** Additionally**,** for CO_2 to achieve multi-contact miscibility (MCM) the pressure requires to be above 10-15 MPa **(Mathews, 1989).** However, temperature affects CO_2 solubility in crude oil, with increase in the temperature the solubility of CO_2 decreases due to reduction in its density. As result, causes the MMP to increase with temperature **(Xu et al., 2020).** This back-up the screening criteria discussed by **Shaw and Bachu (2002)** on low reservoir temperature. Despite that, in compare to water solubility in crude oil, CO_2 solubility in crude oil is 3-9 times higher, resulting in volume expansion and reduction oil viscosity, as well as reduce the interfacial tension between oil and water. Hence, improve the sweep efficiency, but low viscosity and density of CO_2 can lead to gas channeling, which also occurs in N_2 injection **(Jian et al, 2019).** CO_2 injection is used for heavy and light oil extractions **(Mangalsingh and Jagai, 1996: Nobakht, Moghadam, and Gu, 2007: Ghedan, 2009: Zekri, Shedid, and Almehaideb, 2013: Ma et al., 2016; Seyyedsar et al., 2016: Kamali, Cinar, and Le-Hussain, 2015)** and for sandstone and carbonate **(Hawez, and Ahmed, 2014: Ayatollahi, Takband, and Razi, 2015: Vesjolaja et al., 2015: Seyyedsar, Ferzaneh, Sorhrabi, 2017: Siara, Janna, and Le-Hussain, 2020: Okovat et al., 2020).**

2.1- CO_2 Injection for Carbonate and Sandstone Reservoirs

In a research done by **Yin** in **2015** on 134 projects done on CO_2 injection from 1996 to 2014 showed that CO_2 flooding applications are not sensitive to reservoir lithology.

The first CO_2 injection pilot test was done at Mead-Strawn Field on December 1st, 1964 by injecting 4% PV of CO_2 slug then followed by carbonated water of 12% PV later by brine **(Holm and O'Brien, 1971).** The pilot test was done in limey and shaly area with poor average permeability 9 md (to air) and porosity of 11%, and first the reservoir pressure was increased from 115 to 850 psi by waterflooding then the pilot test using CO_2 injection was conducted. The average production before using CO_2 injection was recorded to be less than 40 B/D average. Slightly irregular five spot with two production and four injectors was used. 5000 tones of CO_2 were injected into the four injectors. At a rate of about 55 tons/D was constantly injected for three months. The carbonate water injection started on March 1, 1965 by using WAG injection method. Then 7% of brine was used as driving fluid. CO_2 slug and carbonate water injection were done between 50 and 300 B/D/well with surface pressure of 650 to 900 pisg. Although the volume of water being injected into the pilot test was reduced due to corrosion, the production rate was maintained constant due to expansion of CO_2 into the reservoir. The results showed that at the end of the waterflooding and CO_2 flooding 53% to 82% more oil was recovery by CO_2 in compare with waterflooding. Moreover, less than 10% of the injected CO_2 was produced and no channeling occurred with CO_2, while water caused channeling when used to increase the pressure of the reservoir before CO_2 injection.

Chung et al (1988) stated that despite the high displacement efficiency of CO_2 injection, factors such as reservoir heterogeneity, gravity segregation, and mobility of the fluids determine the sweep efficiency and oil recovery. For carbonate reservoirs it has been reported that due to CO_2 mobility and heterogeneity of carbonate reservoir CO_2 injection can lead to viscous finger and gravity override **(Choi et al, 2003).** Therefore, **Choi et al (2013)** controlled the mobility of CO_2 by foam leading to more favorable results and reducing the relative permeability of CO_2 and increasing CO_2 viscosity. The simulation done using hybrid discrete fracture network, showed that the during 3 years of production CO_2 breakthrough occurred at 300 days for CO_2 injection but was not observed for CO_2 foam injection. In addition, saturation of oil reduction reached 16% of the total distance after 3 years of production for CO_2 injection, but took CO_2 foam only 1.5 years to cover the total distance. Despite the different results, both methods exhibited the same reaction towards higher CO_2 injection. The higher the CO_2 injection led to earlier CO_2 breakthrough and lower oil production. Additionally, **Hawez, and Ahmed (2014)** constructed using Eclipse 300 a compositional reservoir simulator for 3D model on carbonate reservoir to analyze the effect of CO_2 injection on recovery. Five spot model was designed for carbonate reservoir 0.07 to 0.18 porosity, 10 mD to 77mD, 4000 Pisa initial pressure, 219^{o}C temperature, 0.7 and 0.2 intimal saturation of oil and water respectively. The results showed that oil recovers significantly using miscible injection, with field oil efficiency of 0.44, in compare to immiscible injection, with field oil efficiency of less than 0.1, after 20 years of production life. However, some unswept zones, low permeable zones, were detected at the end of the production life due unfavorable mobility ratio that led to gravity override. Even though during miscible highest gas production was recorded due to CO_2 dissolving and reducing the oil viscosity, as result, causing viscous fingering and gas segregation. In compare to immiscible injection that showed no gas production over the 20 years of production, miscible injection still had better sweep efficiency and higher oil production by reducing the oil density. WAG was used to controls the mobility, increase viscosity and density, which led to improving recovery efficiency and causing later breakthrough time.

Similarly, to carbonate reservoirs, **Kamali, Le-Hussain, and Cinar (2015)** experiments done on homogenous sandstone 28 cm in length and 2.65 cm in diameter with 23.8% porosity, 1.7 decries permeability and 27% connate water saturation also experienced early breakthrough, which was reported to be due to either gravity override or viscous fingering, or both. **Seyyedsar, Farzaneh, and Sohrabi (2017)** performed four different core flood experiments on sandstone samples using low-density CO_2 injection. The results showed 57% overall recovery using CO_2-WAG injection. However, in case of the East Vacuum Grayburg San Andres Unit (EVGSAU), which main composed of limestone, in south-eastern New Mexico, which started CO_2 injection in 1985 with WAG ratio of 2:1, and still CO_2 injection is being used and has recovered about 12.5% OOIP in unit overall. Despite, the high mobility of CO_2 causing low sweep efficiency and low reservoir pressure in some areas, the unit oil recovery still passed 150 MMSTB with overall recovery factor of 55% OOIP in the flooded CO_2 area **(Moffit et al., 2015).**

On the other hand, **Okhovat et al (2020**) conducted an experimental study to investigate the effect on carbonate reservoir’s physical properties when carbon dioxide injection is used as enhance oil recovery method using core plugs. In order to investigated the permeability alteration of the rock and the effect on the oil recovery, CO_2 is injected at high temperature and pressure into different samples of carbonate cores to study factors such as injection rate, miscibility region, value of connate salinity, type of injection affect permeability and recovery factor. In experiment, kerosene was used as the oil phase with MMP about 1500-1800 psi, CO_2 as gas phase, NaCl was used to make brine with concentration of 40,000 ppm, and carbonate cores with initial permeability and porosity that varied form 1-5 md and 22-27%, respectively were used. The experiment was conducted using X-ray power diffraction analysis and core CT-scan to identify the rock's mineralogy and heterogeneity. Five Miscible experiments were conducted at 2700 psi of test pressure, and two immiscible experiments were performed at test pressure of 1000 psi, so the experiment will be as accurate as possible. In addition, CO_2 injected into the core at three different rates, 10, 20, and 30 cc/h, where five were performed with injection rate of 30 cc/h and brine with higher concentration of salinity, 130,000 ppm, was used for one of the latter injection rates. The measurements of the change in permeability were taken after 25 pore volume injection, to test the effect of injection rate on permeability alternation. The results show that the permeability alteration depends on the injection rate. For instance, the core plugs 1, 2, and 3 that were flooded with miscible CO_2 at different resulted reduction of the ratio of permeability after the flood to the initial permeability as the injection rate was increased. However, core plugs 4 and 5 that were flood with immiscible and miscible mode respectively but constant injection rate resulted in lower oil recovery and no significant change in the physical properties of the rock for the immiscible flooding in compare to miscible flooding. Thus, in miscible CO_3 injection due to the interaction between CO_2 and water leads to more intense chemical reaction and decrease in the permeability, and higher oil recovery. In addition, for reservoir with saline connate water the injection of CO_2 is less risky, since it reduces the chemical reaction.

2.2 Comparison between Immiscible and Miscible CO2 Injection

Miscible zone between the crude oil and CO_2 causes low saturation of residual oil swept zones, since it improves the microscopic displacement efficiency **(Saira, Janna, and Le-Hussain, 2020)**. Miscibility between crude oil and injected fluid, in this case CO_2, is achieved by obtaining the minimum miscibility pressure.

In order to obtain a good displacement efficiency minimum miscibility pressure (MMP) need to be achieved. Although it is known as pressure increases miscibility also increases along with the oil recovery, but above MMP the recovery factor increases only slightly **(Lake, 2010)**. In addition, the reservoir temperature, oil composition and oil viscosity affect MMP **(Sheng, 2013)**. MMP is determined through slim tube tests, multi-contact tests, mixing cells methods, empirical correlations, compositional simulations of slim tube displacements, analytical methods using equation of state and method of characteristics **(Sheng, 2013).** The phase behavior of the fluids determines whether the miscibility is, First Contact Miscible (FCM) or Multi-contact Miscible (MCM) **(Asgarpour, 1994)**. First Contact Miscibility is most direct and simplest method that miscibility is achieved, but is the most difficult one to find **(Asgarpour, 1994)**. While, multi-contact miscibility is divided into two processes, condensing and vaporization **(Asgarpour, 1994)**.

In United State 1996 number of projects active using miscible CO_2 were nearly 60, while in other countries such as Canada nearly 40 active projects are conducted on miscible CO_2 injection **(El-Hoshoudy, and Desouky, 2018).** Also, in 2014 about 126 million tons of oil were recovered using 128 miscible CO_2 flooding projects conducted in 22 companies in USA **(Jishun, Haishui, and Xiaolei, 2015).** Among the 128 miscible CO_2 flooding reservoirs 39 were sandstone reservoirs, and 55 were carbonate reservoirs, while the remaining were kieselguhr, uncemented sandstone, etc.… The results show a single well production of carbonate reservoir and sandstone is 8.12 t and 4.59 t respectively, and with annual output of 803 $\times 10^4$ t for carbonate reservoir and 265 $\times 10^4$ t for sandstone reservoir. Moreover, limestone reservoirs that were only 9 among the total project, but produced quite high in compare to few number reservoirs. For limestone reservoirs a single well produced 5.33 t and 223$\times$ 10^4 t of annual output. Porosity and permeability are considered important factors in selection of the selection of displacement method depending on the reservoir permeability and porosity. For high permeability and porosity water flooding will also be an effective choice, but for low porosity and permeability reservoirs water flooding can lead poor sweep efficiency and mobility. While miscible CO_2 injection it was the results indicate for reservoir porosity less than 10%, which were 28 projects among the 128 and with 106 of them with porosity less than 20%, there average daily production was 3.51t for a single well **(Koottungal, 2014 cited in Jishun, Haishui, and Xiaolei, 2015).** Similarly for low permeability reservoirs, the results show for the 52 projects that had permeability less than 10× $10^{-3}\mu m^2$ average productions were 2.43t daily for a single well **(Koottungal, 2014 cited in Jishun, Haishui, and Xiaolei, 2015)**. Furthermore, in investigation on miscible CO_2-EOR reported that similar to screen criteria of **Shaw, and Bachu, (2002)** on temperature, for projects, which were 31 projects in 2014, with temperature higher than 65°C the annual production was determined to be 235.63×10^4 t. However, the annual production for projects with temperature between 38-65°C, which were 81 projects in 2014, was 937.94×10^4 t. It has been proven through experiments and theory that using miscible CO_2 injection higher amount of oil is recovered in compare to implementing immiscible CO_2 injection **(Jishun, Haishui, and, Xiaolei, 2015).**

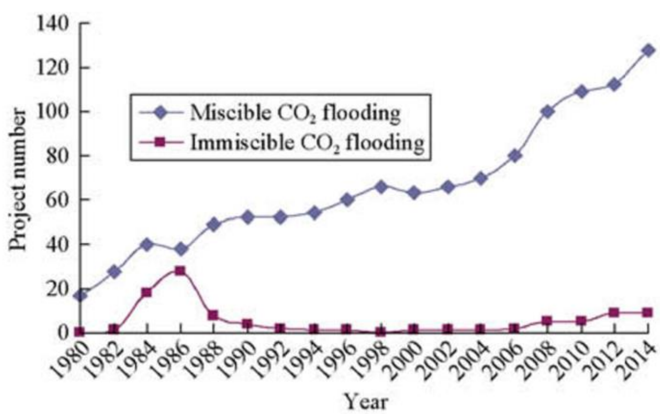


Figure 2.2-2 - Number of Miscible and Immiscible CO2 injection Projects in USA (Jinshun, Haishui, and Xiaolei, 2015)

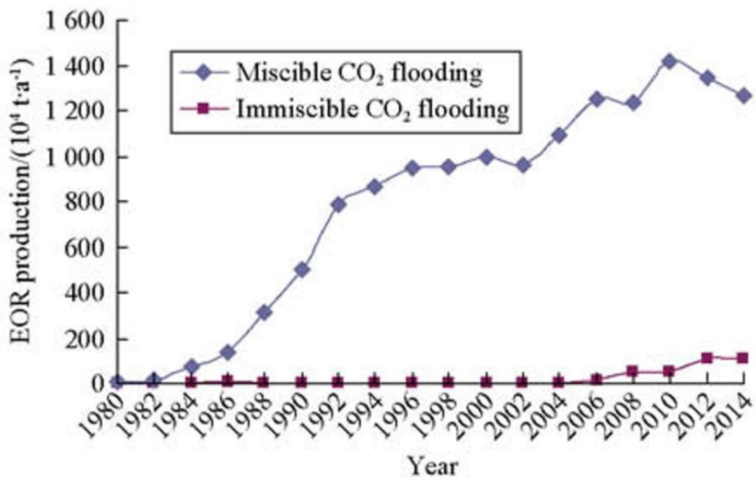


Figure 2.2-3 - EOR production using Miscible and Immiscible CO2 Injection in USA (Jishun, Haishu, and Xiaolei, 2015)

For example, in 2014 out 137 projects using CO_2 injection, 128 were miscible CO_2 injection with production of 1,264 × 10^4 t/a. While only 9 immiscible projects were implemented in 2014 with 107 1,264 × 10^4 t/a **(Koottungal, 2014 cited in Jishun, Haishui, and Xiaolei, 2015)**. From the figures, the number of projects implemented and there production using miscible and immsible displacement is compared and as it is shown miscible CO_2 flooding leads in both. Furhtermore, the initial oil saturation for misible and immicible flloding projects in USA were quite similar, which were 50.88% and 47.43%. However, the results showed that immisicble floodling has lower recovery as oil saturation at the end of production was determined to be 39%. On the other hand, for miscible was 29.37%.
Another example on compraision between miscible and immiscible flooding, a numerical investigation done by **Sira, Janna, and Le-Hussian (2020)** on sweep efficiency and CO_2 storage using modified CO_2 injection and pure CO_2 injection with two models 1D and 3D. The 3D model simulation was done for three different displacements; miscible, near miscible, immiscible at 14.5 MPa, 11.7 MPa, 9 MPa respectively using field scale simulation model SPE-5. The results determined at p 9.0 PMa for pure CO_2 injection 30% of the bottom layer was swept, while at 11.7 PMa is 44% of bottom layer was swept. Also, in a study done by **Fath and Pouranfard (2014)** on both immiscible and miscible flooding

to determine the ultimate oil recovery of Asmari formation with low permeability matrix and is naturally fractured formation made up mostly of carbonate. The MMP was calculated using one-dimensional compositional simulation of the slim-tube model and was determined to be 4630 psia with 4410 psia average pressure before gas injection and 6200 psia fracturing pressure. Different injection rates with used to find the optimum oil recovery and injection rate for immiscible and miscible flooding. The results showed for the miscible flooding the highest oil recovery and average reservoir pressure after 20 years was 1.041×10^8 STB and 5095 psia, respectively at injection rate of 30,000 Mscf/day. While for immiscible flooding, the optimum injection rate was 17,000 Msf/day with oil production and average reservoir pressure of 9.94×10^7 STB and 3053 psia, respectively after 20 years. In addition, **Kamali, Le-Hussain, and Cinar (2015)** investigated the effect of interfacial tension variation on oil, recoveries of light and heavy hydrocarbons and effects of gravity under different miscibility conditions, and CO_2 relative permeability using a commercial compositional reservoir core flood and simulator. In their investigation three different backpressures, 1,300,1,700, and 2,100 psi, were used to perform the pure CO_2 injection experiment immiscible, near miscible, and miscible displacements, respectively, at 70^{o}C. The results show despite, the early breakthrough of CO_2 in miscible and near miscible displacement in compare to immiscible, the latter recorded 18% less than the other two displacements in terms of ultimate recovery, which was 73% of OIP for miscible and near miscible injection.

2.3 Comparison between CO2 injection in light oil and heavy oil extractions

In a studied done by **Kordorwu, Tetteh, and Mireku (2015)** using EORgui screening software to determine CO_2 EOR as the best recovery method and estimate the required amount of CO_2 and the incremental oil recovery. The study was conducted using well data from a 40-acre 5-spot pattern reservoir filled with saturated oil and solution gas with initial GOR of 600 scf/day and API of 32^o. The reservoir was producing for 4 years, on the second-year water injection started at a constant rate of 195 bbl/day resulting in 53,612.38 STB cumulative oil production (39% recovery factor). The EOR screening results showed that CO_2 gas injection ranked first as the most suitable EOR method with 78%. In 20 years, lifetime of the project the results presented a recovery factor of 16.67% and cumulative oil production of 420667.56 Mbbl, which requires total amount of 3,199 MMscf of CO_2. Moreover, sensitivity analysis was also done on, in order to determine the critical parameters, which oil production dependent on. The results indicated that as the Dykstra Parson's Coefficient and the oil viscosity increases the oil production decreases, which could lead significant formation changes over the year. While, among the four average reservoir pressures, 500, 1000, 1500, and 2000 psi for the first two average reservoir pressures immiscible flooding occurred and the last two runs miscible flooding occurred. The highest production occurred at average reservoir pressure of 2000 psi.

In a study done by **Vesjolaja, et al (2016)** using a near well simulation on a reservoir data from heavy oil crude in Norway sandstone reservoir to determine the optimum differential pressure for oil production in the field and the effect of CO_2 on oil recovery by using relative permeability curves. OLGA and Rocx were the two simulators that were run together, this was done in order to obtain more accurate estimations of the well shut-in and build-up, study of the flow instabilities, cross flow between different layers, gas dynamic and water coning. Corey and Stone II models were used in Rocx to define the relative permeability curves for water and oil, respectively. The simulated reservoir parameters were 60 meters in length and width, and 20 meters in height, with 33% porosity, 19^o API, permeability of 7 D, and 12 cp of oil viscosity at temperature of 76^oC and pressure of 176 bar. Five different models were developed using five different differential pressures, 3, 5, 10, 15, and 20 bars, to simulate the oil production performance. In order to obtain the minimum miscibility pressure, MMP, the reservoir pressure was required to be set at 320 bar at 121^oC, was kept constant throughout simulation period, between carbon dioxide and oil with 20^o API. The optimal differential pressure was chosen to be 10 bars as its results showed a high production rate of 10500 m^3 and reasonable breakthrough time. The results of the simulations showed, as the residual oil saturation was reduced from 0.3 to 0.15 the accumulated oil production increased by 12%, from 10,700 m^3 to 12,000 m^3, and the accumulated water production decreased by 22%, from 90,000 m^3 to 70,000 m^3. Additionally, the oil recovery as residual oil saturation dropped from 0.3 to 0.15 after 120 days increased from 52% to 59%, while the water cut decreases from 88% to 86%.

2.4 Improved CO2-EOR Methods

In 2014 it was reported that annual production of oil using CO_2-EOR in USA was 1,371$\times\ 10^4$t, while the total annual production of oil using CO_2-EOR in world was 1,470 $\times\ 10^4$t from 152 CO_2 injection projects **(Jishun, Haishui, and Xiaolei, 2015)**.

CO_2 is reported to be an effective tertiary EOR method to be used after water flooding **(Aycaguer, Lev-On, and Winer, 2001: Beckwith, 2011: Han et al., 2016: Eliebiet al., 2017: Hamid et al., 2017: Seyyedsar, Ferzaneh, Sorhrabi, 2017)**. In order to increase the reservoir pressure and reduced risks, such as the connection between injector and producer, and facility costs, before using gas flooding, almost all the gas flooding undergo water flooding beforehand **(Sheng, 2013).** Moreover**,** gas flooding can be implemented in various ways such as, continuous gas injection, conventional alternating water and gas injection (WAG), tapered water alternating gas (TWAG), cyclic gas injection also known as huff and puff, crestal Gravity Stable Gas Injection (GSGI), injection in the Residual Oil Zone (ROZ) **(Sheng, 2013: Rotelli et al., 2017)**. The two widely used methods in the USA are WAG and continuous injection as both methods are proven to be economically feasible **(Rotelli et al., 2017)**.

Another example, to evaluate the performance of CO_2 tertiary injection and modified CO_2 injection by carbonate water on oil recovery and sweep efficiency of a carbonate sample, **Ayatollahi, Takband, and Riazi (2015)** did two sets of experiment using the two different injection technique. The data for the parameters used in the experiments are from an Iranian petroleum company. The fluids are crude oil, which at temperature and pressure of 40^0C and 13.8 MMPa respectively the oil viscosity is 42 cp and 27.4 API gravity. In addition, brine is used for injection and saturating the core sample with 10,000 ppm and 41,000 ppm respectively, and the last fluid is CO_2. The carbonate water is prepared by mixing CO_2 and water at pressure and temperature of 14.8 MMPa and 40^0C respectively. The core sample porosity is 18.9% with 10.1 mD permeability, which were determined using Helium porosimeter and core Eval apparatus. The first experiment was done by injection of CO_2 after water-flooding, while the second experiment before CO_2 injection, carbonate water was injected for 1.5 times of the pore volume to eliminate the effect of water shielding and improve the sweep efficiency by changing the spread coefficient of the fluids. Furthermore, both experiments were done using 0.2cc/min injection rate and the connate water for the CO_2 injection and modified CO_2 injection 23% and 22% respectively. The results show that the modified CO_2 injection ultimate recovery was 95% and the tertiary CO_2 injection ultimate recovery was 75%. The mechanism behind improving oil recovery and the sweep efficiency is by strengthening the reduction of viscosity, diffusion, and oil swelling, along changing the spread coefficient to positive that will cause the oil to spread on oil and reduce the interfacial tension between gas and water.

WAG advantages are it improves the sweeping efficiency as mobility ratio is improved since water is less mobile than CO_2 and less volume of gas is required for injection. This was proven by experiments done by **Seyyedsar, Farzaneh, and Sohrabi (2017).** They performed four core flood experiments at 50^oC and 600 psi to investigate the potential of low-density CO_2 injection for enhanced oil recovery and understand the behavior reservoir under different conditions of production and injection. The four-core flood experiment studied consists of: intermitted CO_2 injection, tertiary injection CO_2, secondary continuous CO_2 injection, and, enhance oil recovery using injection of WAG and co-injection of surfactant solution and CO_2. The experiments were done using 32.1 cm sandstone core plug with 22.84% and 2.73 of porosity and permeability, respectively. The physical properties of the oil sample, such as GOR and oil viscosity, and effect of CO_2 dissolution on the oil viscosity was measured by measuring pressure drop of new oil sample prepared under core flood

experiment conditions. The brine used in the experiment was prepared with 8000 ppm of sodium chloride and 2000 ppm of calcium chloride. The experiment started with injection of methane-saturated brine as secondary oil recovery. Then the tertiary oil recovery began with injection of 1 PV of CO_2 at 1 cm^3/h. However, in order to improve the sweep efficiency and recovery factor, 2 more cycles of water alternating CO_2 were injected. As result, the oil recovery decreased after each cycle as oil saturation reduced after each cycle and water following the easier path. However, the mobility of oil improved due to the oil swelling and oil viscosity reduction, which lead to overall recovery of 57% after the last cycle.
Alshaibi, Ramadan, and Elsounousi (2019) did a study to evaluate and compared the application of different EOR application on Libyan oil field using EORgui software. After the data was input into the screening results recommended applying WAG due the good screening for water flooding, which was being implanted in actual case, and CO_2 flooding. The MMP was obtained from correlations from black oil modelling, which was estimated to be 2120 psia. Sensitivity analysis was done study the effect of injection rate and WAG ratio, the results showed as the increasing the WAG ratio leads to recovery factor to decrease. However, the injection rate had the opposite effect. Therefore, the optimum result was at injection rate of 10,000 bb//day with 0.05 WAG ratio that results recovery factor of 25.22%. In compare to water flooding and WAG flooding, CO_2 flooding showed more effective results using EORgui, which showed to be able to recover 6.5 million barrels from 10 million barrels of residual oil.
Even though miscibility can be maintained between CO_2 and the crude oil but the flow of the fluid can be hindered with asphaltene clogging the pores of the rock. Therefore, additives are used to recover the asphaltene. Therefore, to improve CO_2-EOR by improving the sweep-efficiency for both oil recovery and CO_2 storage, CO_2 injection was treated with ethanol and was injected as Ethanol-treated CO_2 in a numerical investigation done by **Sira, Janna, and Le-Hussian (2020)**. The resulted showed, that ethanol-treated CO_2 is more effective than pure CO_2 when for immiscible displacement than miscible displacement. In

addition, it also identifies that as the pressure increases the difference between the oil recovery and CO_2 storage efficiency of ethanol-treated CO_2 and pure CO_2 injection decreases. Even though, the CO_2 storage efficiency-difference is not that significant in compare to oil recovery-difference, due to some ethanol that remained in the reservoir with CO_2, which caused reduction in CO_2 storage quantity and efficiency of the storage. Similar to IFT-difference, differences of oil recovery and CO_2 storage efficiency increase as pressure increase but then reduces as pressure increases further, so as displacement efficiency is improved due to IFT reduction leads to improvement of oil recovery and CO_2 storage efficiency. Furthermore, at MMP_p IFT difference is zero but the differences of oil recovery and CO_2 storage efficiency recorded at the point were positive. The injected CO_2 is either produced or trapped in reservoir as free phase or it dissolves in the oil. The simulation shows that CO_2 is at first trapped as free phase but significant amount of it dissolves after 0.2 PVI. At the three different pressures, 9,11.7, and 14.5 MPa higher amount of CO_2 was dissolved for ethanol-treated CO_2 injection due to the presences of ethanol and increasing pressure, which causes mass transfer between CO_2 and oil. Thus, the sweep efficiency improves with increase in the density and viscosity with increasing pressure; these properties are higher for ethanol-treated CO_2 than pure CO_2.

Table 2.1 - Recovery and CO2 Storage Difference with respect with Pressure

Pressure - MPa	Recovery-difference (%)	CO_2 storage efficiency-difference (%)
9.00	**13**	**4.8**
11.7	**10**	**4.6**
14.5	**6**	**3.5**

Table 2.2 - Difference between the % of CO2 dissolved for Pure and Treated Ethanol

Pressure – MPa (Displacement type)	Dissolved CO_2 % during Ethanol-treated CO_2 injection at 1 PVI	Dissolved CO_2 % during Pure CO_2 injection at 1 PVI
14.5 (Miscible)	53	36
11.7 (Near Miscible)	48	22
9.00 (Immiscible)	38	19

Chapter 3 - Theoretical Background

In 1950s it was first identified that the mechanism behind oil recovery using CO_2 flooding is oil swelling, viscosity and crude vaporization, which are related to phase behavior of CO_2 and crude oil mixture **(Baviere, 1991).** CO_2 flooding used is in low-permeable and light oil reservoirs, resulted in 10 to 20% improvement in the oil recovery **(Kulkarni, 2003).** CO_2 flooding can be conducted in miscible, near miscible, and immiscible displacement depending on the reservoir temperature, pressure and oil composition **(Baviere, 1991)**. Miscible gas flooding improves the volumetric sweep and displacement efficiencies, since the displacing fluid develops miscibility by getting in contact with the crude oil at the first contact or after multiple contacts **(Claridge, 1972: Mathiassen, 2003)**.

3.1- CO_2 Physical Properties

(Baviere, 1991: El-hoshoudy, and Desouky, 2018) CO_2 under normal conditions is colorless, odorless and heavier than air nearly 1.5 times, but when its concentration reaches 10% in the atmosphere it becomes toxic. CO_2 properties under standard conditions of 1.01 MPa pressure and 0°C temperature are:

Table 3.3 - Properties of CO2

Molecular Weight	44.010 g/mol
Specific Gravity with respect to air	1.529
Density	1.95 kg/m^3
Viscosity	0.0137 mPa/s

At low temperature and pressure CO_2 is in the solid phase, but at -78.5°C temperature the solid phase evaporates and with further increase in the temperature liquid phase is formed coexists with vapor and solid phase at the triple point. As the temperature and pressure continuously increase and reach the critical point CO_2 starts to behave as vapor. In the phase diagram, Figure 5, shows the critical and triple properties of CO_2 are:

Table 3.4 - Properties of CO2 at triple and critical point

Critical pressure	7.39 MPa
Critical temperature	304 K (31.04^oC)
Critical molar volume	94 cm^3/mol
Critical viscosity	0.0335 cp
Triple point pressure	0.51 MPa
Triple point temperature	-56.6^oC

The critical temperature and pressure show that under most conditions reservoir conditions CO_2 behaves as supercritical fluid **(Klins, 1991 stated in Yin, 2015)**. The viscosity of CO_2 (0.00335 cp) at the critical temperature and pressure is higher than the other injection gases such as N_2 (0.016 cp) and CH_4 (0.009 cp).

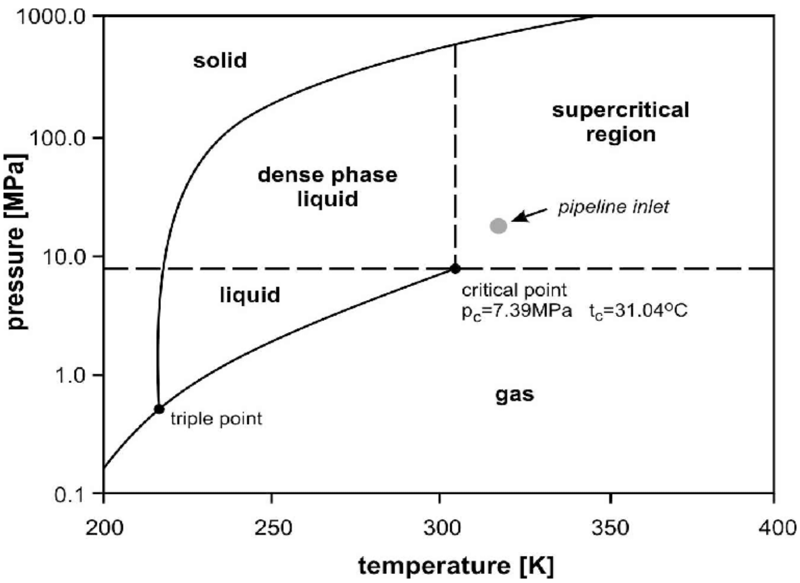


Figure 3.3-1 - Phase Diagram of CO2 (Witkowski, Majkut, and Rulik, 2014)

It can be seen in figure 3.3-1a that at temperatures greater than the critical temperature the CO_2 density increases as the pressure increases. While, for temperature below the critical temperature it is represented using dotted lines, which represent average CO_2 density under average reservoir conditions. Density can be calculated using the real gas law:

Equation 1 - Density Equation for Real Gas Law

$$\rho = \frac{PM}{ZRT} \qquad Equation\ 1$$

Where,

P is pressure

M is molecular weight

Z is gas compressibility factor

T is absolute temperature

Moreover, CO_2 viscosity also depends on temperature and pressure. For a given reservoir temperature as the pressure increases the viscosity of CO_2 also increase. However, the characteristics of CO_2 viscosity and density differ, since CO_2 viscosity is similar to reservoir gas values. While, CO_2 density is similar to liquid values **(Baviere, 1991)**.

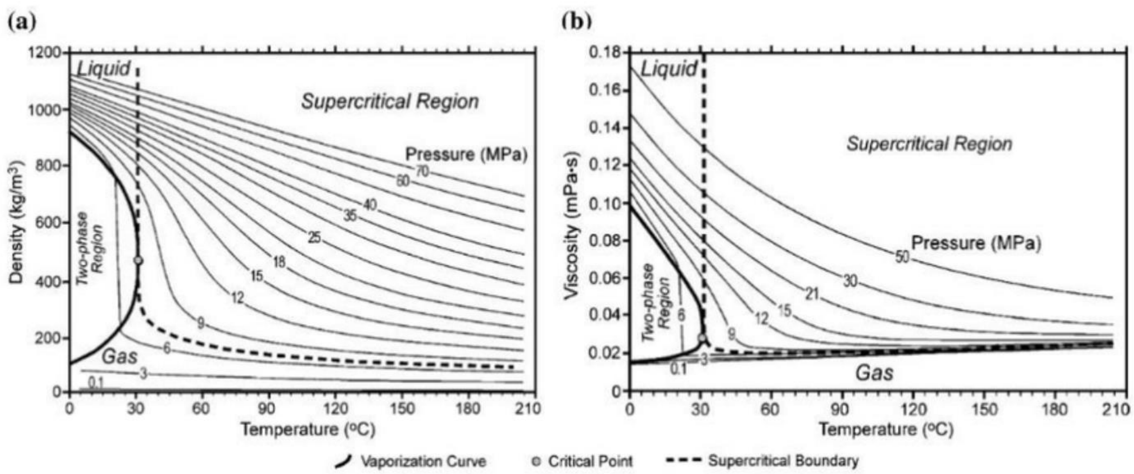


Figure 3.3-2 - Variation of CO2 (a) Density and (b) Viscosity as a function of Temperature and Pressure

In addition, CO_2 solubility in oil also depends on temperature and pressure, along with oil properties **(Baviere, 1991)**. CO_2 is two to ten times more soluble in oil than water **(El-hoshoudy, and Desouky, 2018)**. The dissolution of CO_2 causes oil swelling and reduction of viscosity **(Baviere, 1991)**. The volume of oil increases 10 to 60% due to dissolution of CO_2 into the oil and this is greater in lighter oils, which caused reduction in the residual oil saturation **(Yin, 2015).** Moreover, CO_2 dissolution also causes the viscosity to reduce, which is greater for medium and heavy oils **(Yin, 2015)**. Solubility of CO_2 increases with increase in pressure but decreases as the temperature or salinity of water increases, which demonstrated using figure 3.3-3 **(Mathiassen, 2003)**. CO_2 increases the viscosity of water and creates carbon acids.

$$CO_2 + H_2O \leftrightarrows H_2CO_3$$

This results in stabilization of the clay minerals by lowering the pH, which prevents swelling of clay, in clay-laden rocks. Furthermore, it also improves the injectivity due to the rock's partial dissolution in carbonate rocks.

$$H_2CO_3 + CaCO_3 \leftrightarrows Ca\ (HCO_3)_2$$

$$H_2CO_3 + MgCO_2 \leftrightarrows Mg\ (HCO_3)_2$$

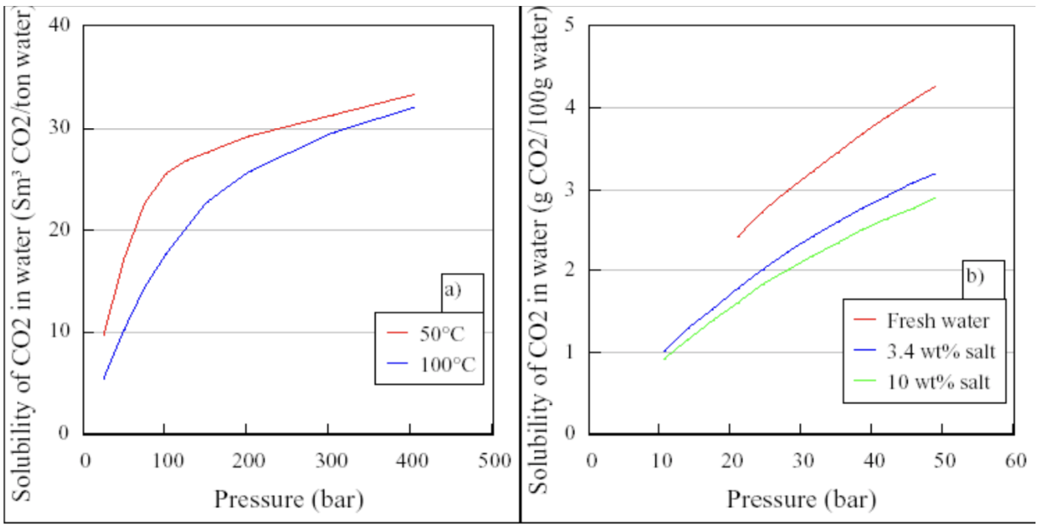


Figure 3.3-3 - Solubility of CO2 in water as function of pressure with a) temperature and b) salinity (Mathiassen, 2003)

3.3 – Miscibility Mechanisms

Saturation of oil with CO_2 using higher amount required causes mass transfer between phases. Subsequently, leading to condensation of CO_2 into oil phase and vaporization of light and medium components of oil into gas phase **(Baviere, 1991)**. Phase diagrams, figure 3.8, are used to describe the different zones formed during process of injection-vaporization in the reservoir cross-section. The relation between the vapor phase and pressure differs depending on the difference between CO_2 concentration and critical point **(Simon, Rosman, and Zana, 1978)**. The volume of the vapor phase is inversely proportional with pressure, when the concentration of CO_2 is lower than the critical point. Moreover, vapor phase volume is directly proportional to pressure when concentration of CO_2 is higher than the critical point.

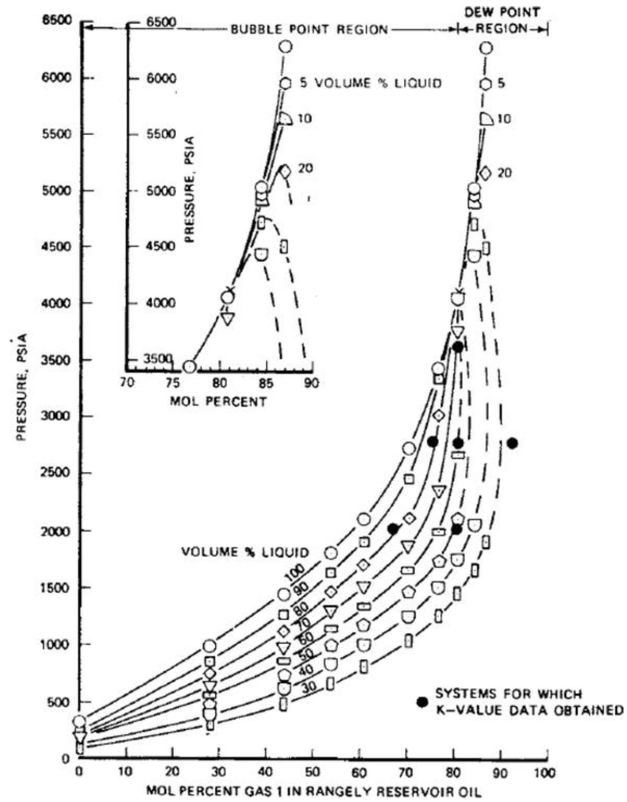


Figure 3.3-4 - Pressure Composition Diagram (Teklu, et al., 2014)

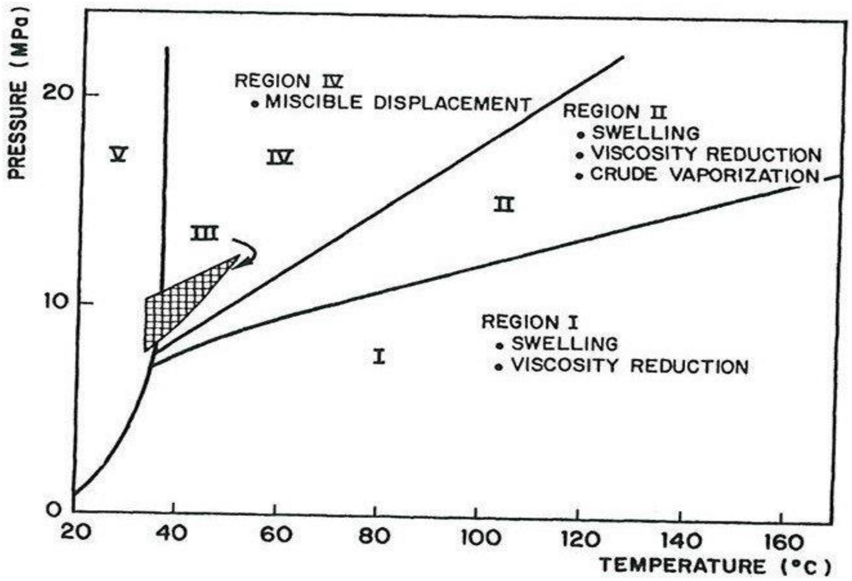


Figure 3.3-5 - The Effect of Pressure and Temperature on CO2 Recovery Mechanisms

Oil recovery using miscible flooding is dependent on oil viscosity reduction, vaporization, mobilizing oil light components, oil swelling, and reduction of interfacial tension **(Thomas, 2008)**. Klins **(1984 stated in Baviere, 1991)** divided CO_2 displacement into five regions based on their characteristics, which shown in the figure 3.9. Moreover, the swelling factor is used as an indication regarding the how efficient displacement will be, which define as:

Equation 2 - Swelling Factor

$$swelling\ factor = \frac{CO_2 saturated\ stock\ tank\ oil\ volume}{original\ stock\ tank\ oil\ volume} \qquad Equation\ 2$$

The relation shows the more CO_2 dissolved in the oil the less viscous the oil **(Forest, 2012).**

The miscibility between crude oil and CO_2 is achieved at first or multiple contacts, which is easier to be reached for light and medium oil at pressure lower than that of dry gas **(Baviere, 1991)**. When the oil in place and fluid injected are mixed together in all proportions without any multiphase behavior then the miscibility achieved is first contact miscibility (FCM). However, solvents that achieve FCM are highly costly such as propane, butane, or mixtures of LPG. CO_2 is generally achieved dynamic miscibility by being in contact with the crude oil through multiple contacts similar to natural gas, flue gas, and nitrogen **(Baviere, 1991:**

Mathiassen, 2003). However, unlike natural gas, CO_2 does not require the presence of hydrocarbon intermediate components in oil in place to achieve dynamic miscibility. The dynamic miscibility is achieved through extraction of a broad range of hydrocarbons from oil in place, which occur at pressure lower than MMP of dry hydrocarbon gas **(Mathiassen, 2003).**

The mixing zone between oil in place and the CO_2 injected is developed by dissolution of up to the saturation pressure. While, the miscibility between the two fluids is developed when during oil displacement by CO_2, mass transfer occurs between oil and CO_2. Both fluids exchange light to intermediate components, and developing miscible zone between the two fluids with no interface **(Baviere, 1991)**. This process is called the dynamic miscibility or the multiple-contact-miscibility (MCM) **(Zhang, Hou, and Li, 2015: Baviere, 1991)**. MCM is developed through vaporizing gas drive process and condensing gas drive process **(Merchant, 2015)**. The lowest pressure required to achieve multiple miscibility contact is expressed as minimum miscibility pressure, regardless of the process **(Mathiassen, 2003).**

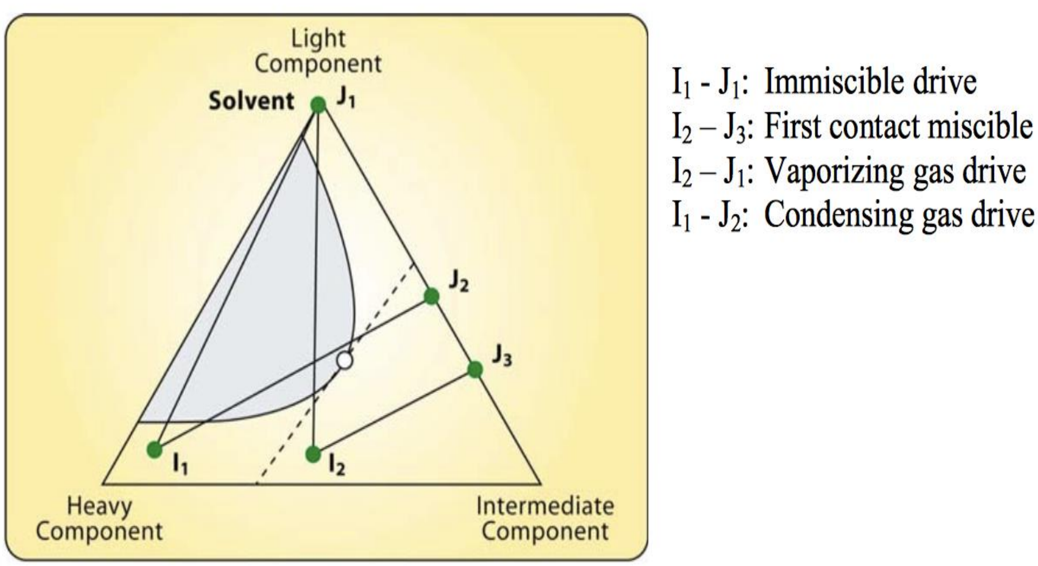


Figure 3.3-6 - Various Oil Displacement Methods using Gas Injection (Mathiassen, 2003)

3.3.1 – Vaporizing Gas Drive Process

Vaporizing gas drive process is based on the vaporization of intermediate components of the oil in place to the injected fluid to create a miscible zone between the two fluids **(Baviere, 1991: Mathiassen, 2003).** In general, C_2 to C_6 are transferred between the reservoir oil and injected fluid due high injection pressure. However, in case of CO_2 lower pressure is required to obtain MMP in compare to the other gases, and CO_2 can extract higher fraction of hydrocarbon molecules, it extracts up to C_{30} **(Mathiassen, 2003).** This process can displace all the oil in place the areas that were swept by the miscible bank, but it depends on the reservoir heterogeneity and flow conditions **(Mathiassen, 2003).**

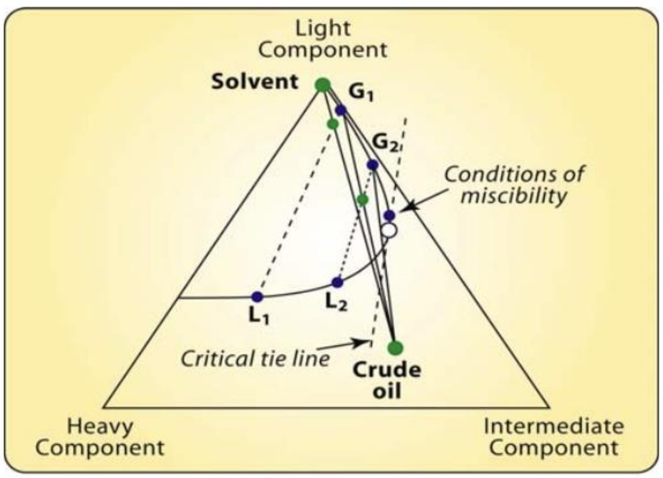


Figure 3.3-7 - Vaporizing Gas Drive Process

The mechanism behind the process can be explained using ternary diagram above. As it can be seen in the diagram miscibility is not achieved at the first contact as the line from the crude oil to the injected gas passes through the two-phase envelope. Since oil and gas are not in equilibrium, various exchange occurs between the two fluids, but miscibility is achieved when the point of oil the pass the critical tie line, as miscibility is achieved at the right side of the critical tie line **(Baviere, 1991: Mathiassen, 2003).**

3.3.2 – Condensing Gas Drive Process

Miscible bank is developed by condensation of the intermediate gas from the rich gas injected to the oil in place. Therefore, a mobile oil bank will be developed, as the oil left behind the injected gas is composed of light components and due to swelling the pore volume of the oil in place increases. This process continues until miscible zone is developed. This process occurs when a gas rich in intermediate hydrocarbons is injected into a heavy oil reservoir **(Baviere, 1991: Mathiassen, 2003)**. Similar to vaporizing gas drive process, condensing gas drive process to achieve miscibility at the right side of the critical tie line.

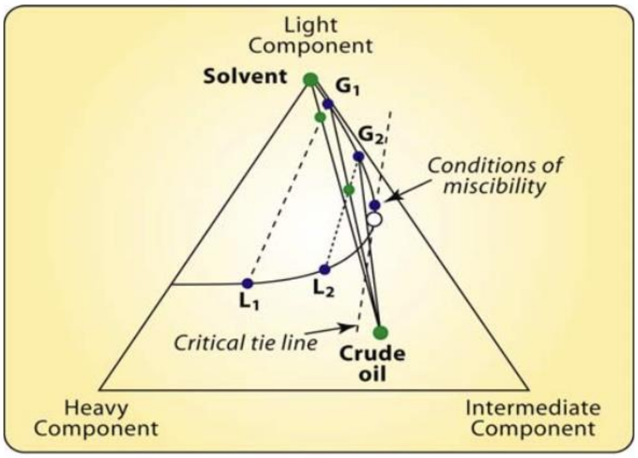


Figure 3.3-8 – Condensing Gas Drive Mechanism

However, CO_2 miscibility is developed through the combination of vaporizing and condensing gas drive mechanism. The vaporized hydrocarbon gas, re-condense into the oil phase at the displacement front leading to favorable mobility characteristics **(Mathiassen, 2003)**.

3.3.3 – Combined Vaporizing-Condensing Gas Drive Mechanism

Simulation and experiments show that miscible displacement using rich gas injection is due to combination of both process, vaporization and condensation gas drive mechanism. **Zick (1986)** and **Novosad and Costain (1986)** reported that:

- The mechanism behind miscibility between reservoir oil and rich gas, when used as injection gas, is combined vaporizing and condensing gas mechanism more likely than only condensing gas drive.
- The pseudo-miscible zone developed by combination gas drive mechanism is similar to condensing gas drive mechanism miscible zone.

- Also, similar to vaporizing gas drive mechanism some residual oil remains trapped after displacement.

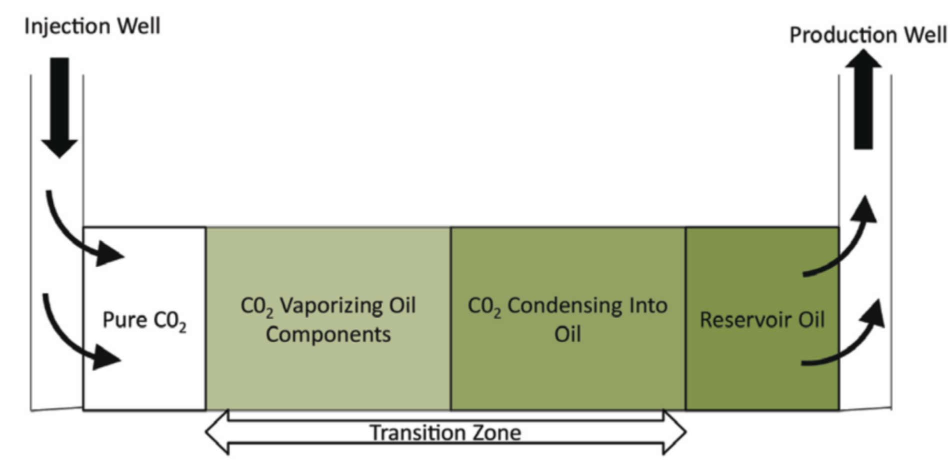


Figure 3.3-9 - CO2-EOR Mechanism (Verma, 2015)

3.3.4 – Minimum Miscibility Pressure

The minimum pressure required to achieve the multiple contact miscibility between the crude oil and injected fluid is defined as the minimum miscibility pressure (MMP). In order to determine MMP, experiments, correlations, and equation of state are used **(Zhang, Hou, and Li, 2015).** The experimental test widely used is slim tube test **(Amao, 2012)**, other known tests are rising-bubble apparatus (RBS), interfacial tension vanish method, steam density method, and multiple contact method **(Harmon, and Grigg, 1988: Srivastava, and Huang, 1998: Nobakht, Moghadam, and Gu, 2008: Adyani, et al., 2009)**. Although, experimental method is the standard method and equation state is precise and fast, but the method used the mainly is correlation. Since, experiments require a long time and money, while it is difficult to give clear standard judgments on the miscibility function using equation state. Since, MMP is effect by temperature and the composition of oil and gas, most correlations take into consideration reservoir temperature, concentration of intermediate components, and the molecular weight of the heavy components **(Baviere, 1991).** In 1983 the first correlation of

Stalkup was published **(Stalkup, 1983).** The investigation showed the factors that effect MMP:

- The higher the reservoir temperature the higher the MMP.
- More the total amount of C_5 to C_{30} present the lower the MMP.
- However, Lower the individual the molecular weight of the individual C_5 to C_{30}, the lower the MMP.
- The properties of heavy components, C_{30}^+, effects MMP more than > C_{30}.
- C_2 to C_4 is not required for MMP.
- MMP is not affect significantly by the presence of methane in the reservoir.
- When either the density of CO_2 is higher that of dense CO_2 gas or liquid CO_2 solubilizes C_5 to C_{30} hydrocarbons in the reservoir oil, MCM is achieved.

In investigation done by **Høier and Whitson (1998)** concluded that MMP increases with depth for mechanisms of vaporizing and combined condensing and vaporizing. In addition, MMP is always greater than or equal to the bubble-point pressure in case of vaporizing mechanism. On the other hand, for it is great than or less than bubble point pressure for combined condensing and vaporizing mechanism.

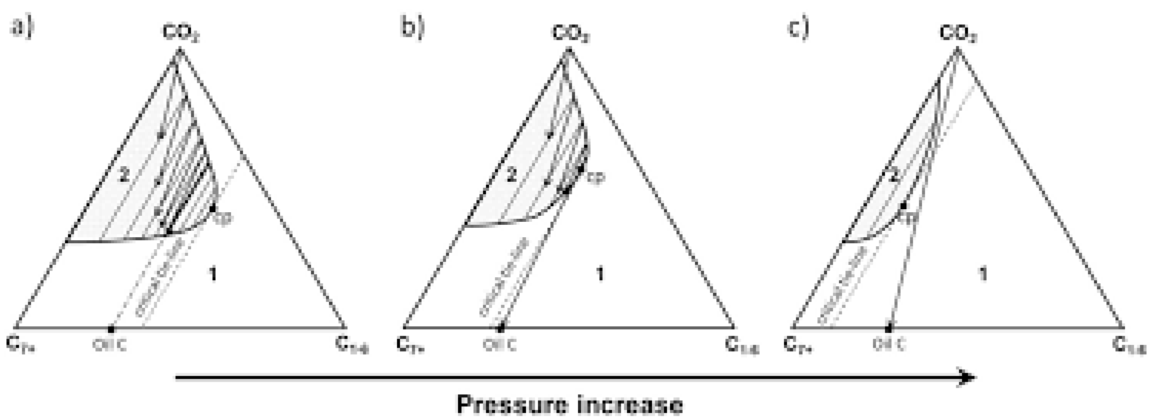


Figure 3.3-10 - CO2 Tertiary Diagram as Pressure Increases (Rommerskirchen et al., 2016)

3.4 - Sweep Efficiency of Miscible CO_2 Injection

One of the main drawbacks of CO_2 flooding is its high mobility, which leads to gravity tonguing and viscous finger due to the lower viscosity and density of CO_2 in compare with the oil in place **(Baviere, 1991).** As result, significant amount of

CO_2 injected flows the easier path, the swept areas. Attempts to improve the sweep efficiency are the following:

- Installing well packers and perforating techniques
- In order to, eliminate the low pressure drops the production wells are shut-in.
- CO_2 injection design depending on the reservoir geology, fluid and rock properties **(El-hoshoudy, and Desouky, 2018)**

Some examples of the last point are, continuous CO_2 injection, continuous CO_2 injection followed by water, conventional water-alternating-gas (WAG), tapered WAG, WAG followed with gas, and CO_2 foam injection (**Baviere, 1991: El-hoshoudy, and Desouky, 2018)**.

3.5 CO_2 Flooding Screening Criteria

In the table 3.5 the main parameters required are included in the screening criteria for CO_2 flooding are summarized by **El-hoshoudy, and Desouky (2018),** which include the depth, reservoir temperature and pressure, porosity, permeability, oil gravity and viscosity, reservoir type, etc**.** Reservoir size and potential hydrocarbon recovery is factors that are depended on if any of the criteria's do not meet the optimum conditions required. In order to evaluate the reservoir behavior, the OOIP is calculated. The volumetric calculation of the OOIP is done using the following equation:

Equation 3 - Volumetric OOIP

$$OOIP = \frac{7758 \times A \times H \times \emptyset \times S_{oi}}{B_{oi}} \qquad Equation\ 3$$

Where,

A: reservoir area, acres

H: average net reservoir thickness, ft

Ø: Average porosity formation

S_{oi}: initial oil saturation

B_{oi}: oil formation volume factor at initial pressure, bbl/STB

7758: constant converting factor, bbl/acre-ft

Recovery factor is a function of lithology, porosity, permeability, capillary size, wettability, oil gravity, oil viscosity, the percentage of medium to higher molecular weight components,

Table 3.5 - Miscible CO2 Flooding Screening Criteria

Criteria	Optimum Conditions
Depth, ft	2500-3000 ft
Reservoir Temperature, ^{o}F	<120^{o}F
Reservoir Pressure, psi	>3000 psi
Reservoir Type	Carbonate reservoirs is more favorable than sandstone
Oil Gravity, ^{o}API	27-39^{o}API (medium – light oils)
Oil Viscosity, cp	< 3 cp
Oil Saturation	> 20 %
Total Dissolved Solids (TDS), mg/L	<10, 000 mg/L
MMP, psi	1300 -2500 psi
Net Pay Thickness, ft	75 -137 ft
Porosity	> 7%
Permeability	> 10 mD

Chapter 4 - Methodology

4.1 – Field Data

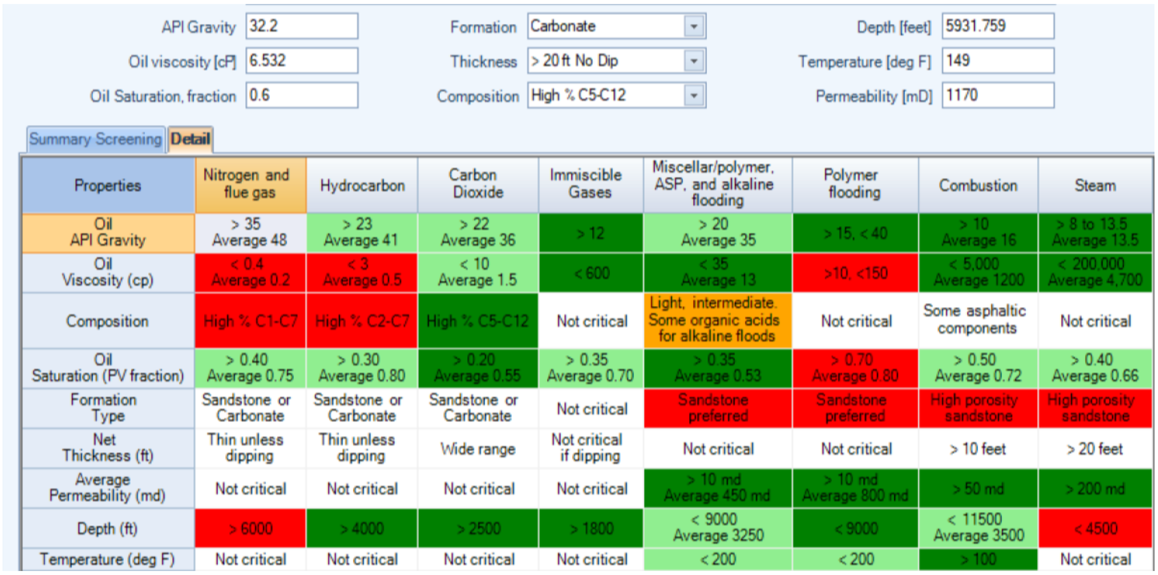
The data used in this report is from X reservoir from Kurdistan region licensed by DNO company. The reservoir formation is Euphrates, composed of mainly carbonates, at depths of 1801 meters.

4.2 – Fluid Data

CO_2 gas is injected into the reservoir, using WAG method. Water is first injected into the reservoir to maintain the reservoir pressure above the bubble point pressure before CO_2 is injected into the reservoir. The WAG ratio for CO_2 injection is set at 0.05, with the total pore volumes of the WAG and chase water injected set at 4.

4.3 – Screening Method

In this report EORgui software was used for screening and analyzing the field data. EORgui software follows EOR Screening Criteria Revisited by Taber, Martian, and Seright, published on 1996. EORgui software provide quick screening and ranking appropriate EOR methods for the oil field summary of its reservoir and fluid properties. Additionally, it organizes input files necessary for technical analysis portions of the publicly available Fortran applications. The Fortran applications are runned at Graphical User Interface (GUI) and then imports the results back into the applications. The results of the runs were input into tables using Microsoft Excel and also plotted into high quality charts.



Properties	Nitrogen and flue gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscellar/polymer, ASP, and alkaline flooding	Polymer flooding	Combustion	Steam
Oil API Gravity	> 35 Average 48	> 23 Average 41	> 22 Average 36	> 12	> 20 Average 35	> 15, < 40	> 10 Average 16	> 8 to 13.5 Average 13.5
Oil Viscosity (cp)	< 0.4 Average 0.2	< 3 Average 0.5	< 10 Average 1.5	< 600	< 35 Average 13	>10, <150	< 5,000 Average 1200	< 200,000 Average 4,700
Composition	High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate. Some organic acids for alkaline floods	Not critical	Some asphaltic components	Not critical
Oil Saturation (PV fraction)	> 0.40 Average 0.75	> 0.30 Average 0.80	> 0.20 Average 0.55	> 0.35 Average 0.70	> 0.35 Average 0.53	> 0.70 Average 0.80	> 0.50 Average 0.72	> 0.40 Average 0.66
Formation Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net Thickness (ft)	Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	> 10 feet	> 20 feet
Average Permeability (md)	Not critical	Not critical	Not critical	Not critical	> 10 md Average 450 md	> 10 md Average 800 md	> 50 md	> 200 md
Depth (ft)	> 6000	> 4000	> 2500	> 1800	< 9000 Average 3250	< 9000	< 11500 Average 3500	< 4500
Temperature (deg F)	Not critical	Not critical	Not critical	Not critical	< 200	< 200	> 100	Not critical

Figure 4-1 - EOR Screening Criteria for the Reservoir

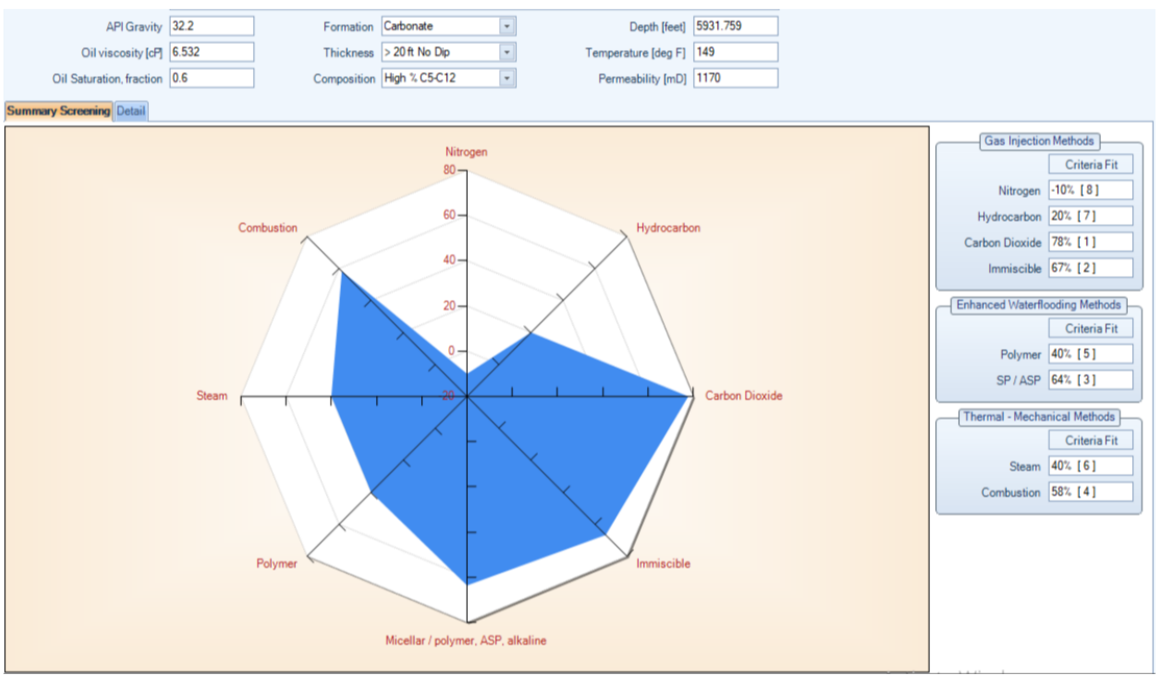


Figure 4-2 - Results for Screening Criteria

As it can be seen from the graph CO_2 injection is the most suitable EOR method by 78%.

4.3 – Simulation of the CO_2 Miscible Flooding Model

The miscible CO_2 model used in the EORgui software is a three-dimensional, which is layered with pattern type of five-spot, two-phase, which is composed of aqueous and oleic, and three components, which includes oil, water, and CO_2. Factor such as Koval (1963) factor, Dykstra-Parson coefficient (1950), and Claridge's procedure (1972) are used to for to take in account the influence of viscous fingering and gravity segregation, to calculate the permeabilities, used to correct the areal sweep, respectively.

Modified fractional theory for effects of viscous fingering, areal sweep, vertical heterogeneity and gravity segregations was used to determine the breakthrough and recovery of oil and CO_2 for the reservoir model. After the required data was "input" and the unfilled properties the software uses default parameters.

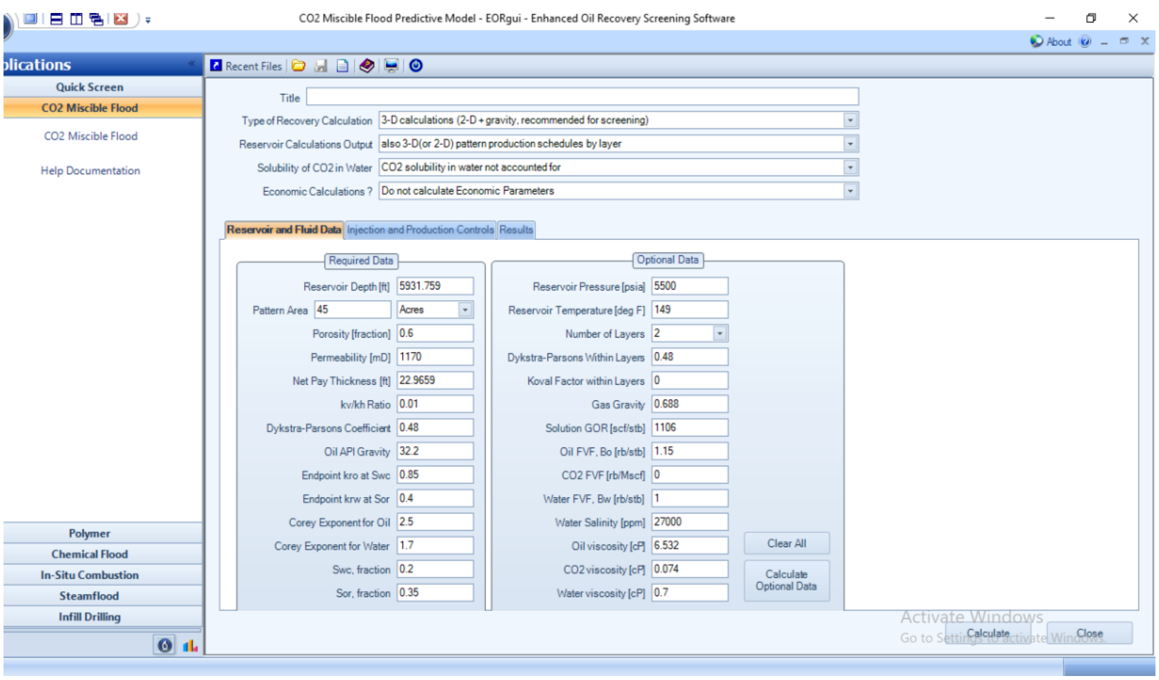


Figure 4-3 - Miscible CO2 injection reservoir and fluid data

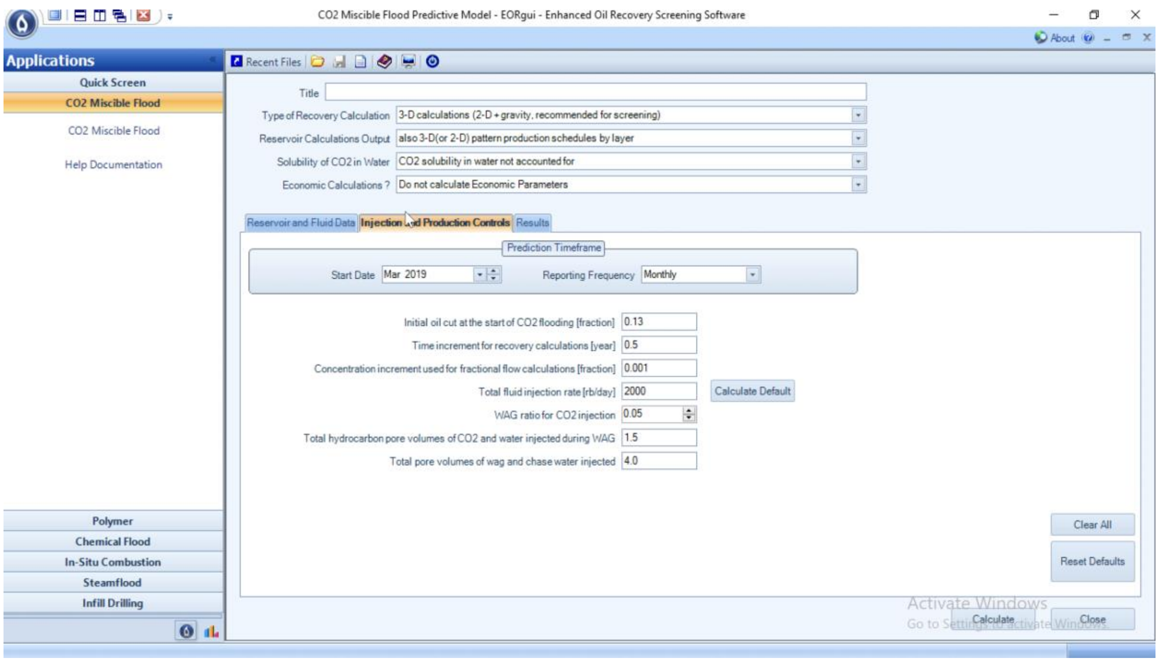


Figure 4-4 - Miscible CO2 injection and production controls

After all data was input into the software it was calculated by pressing the "calculate" button. Sensitivity analyses was done by using different total fluid injection rates to obtain the optimum injection rate and production rate.

Chapter 5 - Result and Discussion

5.1 – Results

CO_2 injection started at March 2019, however the changes due to the injection of CO_2 started after 7 months. The oil production rate started to rise and the highest oil production was recorded at 308.8 bbl/d after a year and 2 months. However, after oil production rate reaches its peak, it starts to decrease gradually.

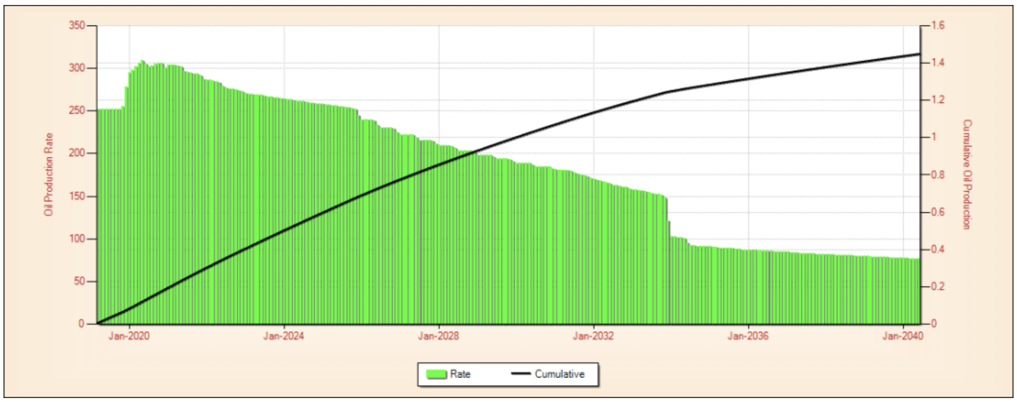


Figure 5-1 - Oil Production Rate and Cumulative Oil Production vs time

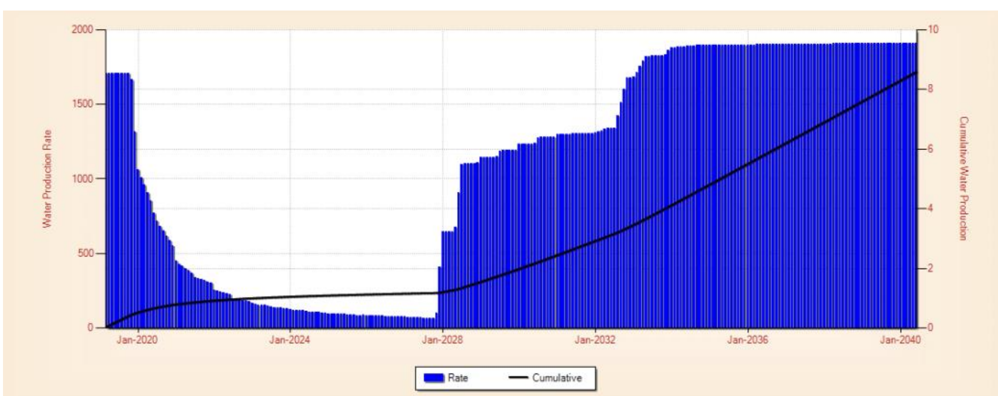


Figure 5-2 - Water Production Rate and Cumulative Water Production vs time

The water production is high at the start of the simulation then decreases afterwards, since the initial displacement method was water injection, so high amounts of water is produced. However, after the displacement method is altered to CO_2 injection the water production starts to decrease from 1709.8 bbl/d to 839.2 bbl/d after a year and 2 months, at the highest oil production. Water production starts to raise again after January 2028 as the displacement method is altered back to water injection only and miscible CO_2 injection stops at November 2027. Although miscible CO_2 injection stops at November 2027, some amounts of CO_2 dissolved with the oil is still present and are produced, and until the end of the CO_2 production the oil production decreases gradually. After no more CO_2 was produced, a sharp drop in the oil production is preserved after November 2033, since the oil displacement afterwards depends on waterflooding only.

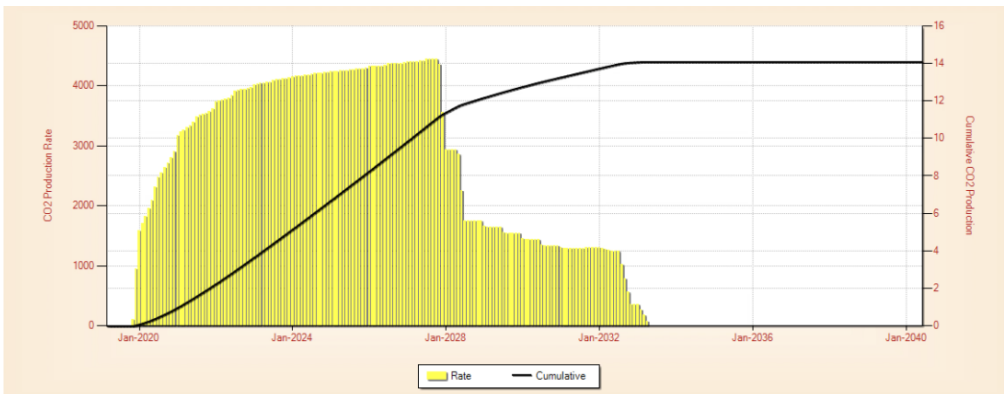


Figure 5-3 – CO2 Production Rate and Cumulative CO2 Production vs time

After CO_2 breakthrough the oil production starts to increase and the CO_2 production increases also. In addition, as it can be seen in figure 5-3 there is still CO_2 production after November 2027 even though the injection stopped. Once CO_2 injection and production stops the oil production drops from 214.3 to 154.6 bbl/d, respectively. At the end of CO_2 production, the cumulative oil production is 1204.76 Mbbls/d with OOIP of 36.5%. Although the cumulative oil production by the end of simulation is 1425.88 Mbbls/d, the oil production rate after April 2033 continues to decreases, so it is more favorable to stop production after April 2033.

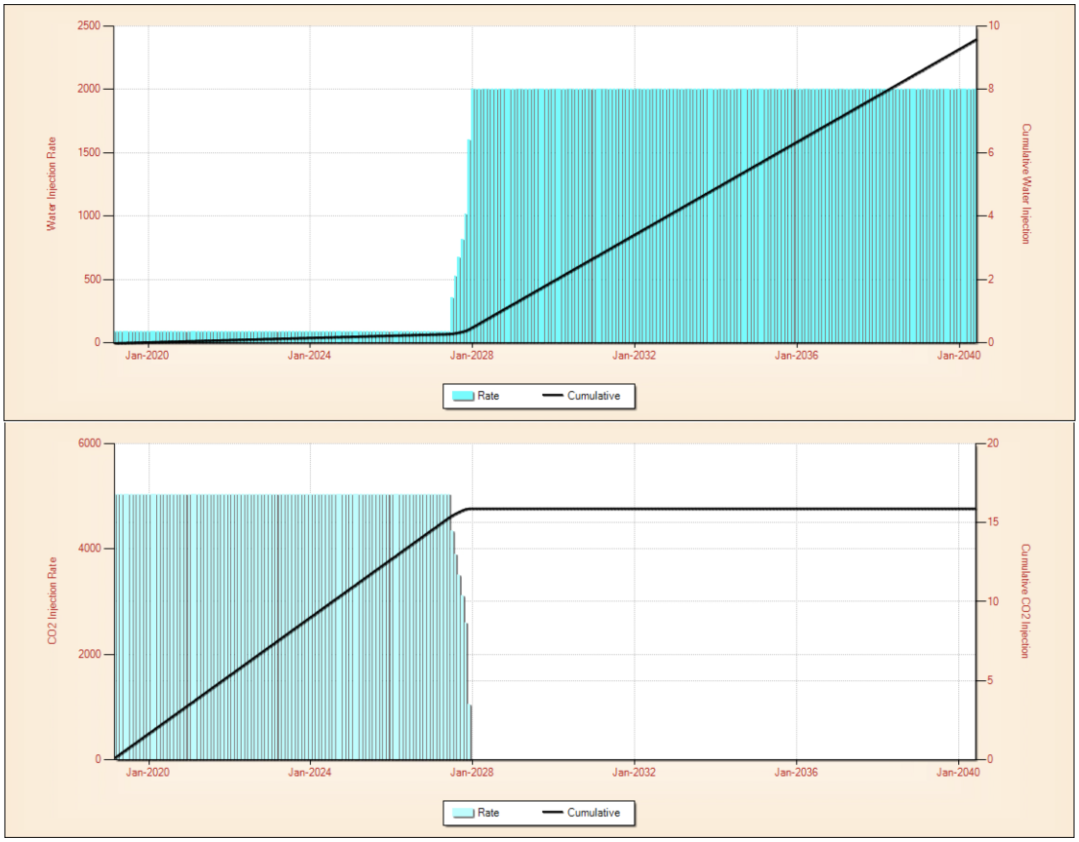


Figure 5-4 - Water and CO2 injection

5.2 – Sensitivity analyses Results

Three different cases were tested by changing the injection rate to 2500, 3000, and 3500, which are named case 2, 3, and 4, respectively. The oil production rate is highest when injection rate 3500 rb/d is used but life of the reservoir well is shorted as CO_2 injection is stopped at July 2024. However, as there is still miscible CO_2 mixed with the oil the oil production decreases gradually after July 2024 and the last CO_2 production is recorded at July 2027, after three years. Even though the simulation is predicted that the oil production with WAG is effective until May 2031 and production stops then, the cumulative oil production is 1492.94 Mbbl/day with OOIP of 44.71%. The cumulative production and OOIP at July 2024 are 1278.65 Mbbl/d and 38.29%, respectively.

For injection rate 2500 and 3000 rb/d the highest oil production rate predicted is at 401.4 bbl/d and 449.2 bbl/d, respectively. Similar to 3500 rb/d, early CO_2

breakthrough is perceived. However, the oil recovery for 2500 rb/d and 3000 rb/d was 37.83 % and 38.7% at the last CO_2 production.

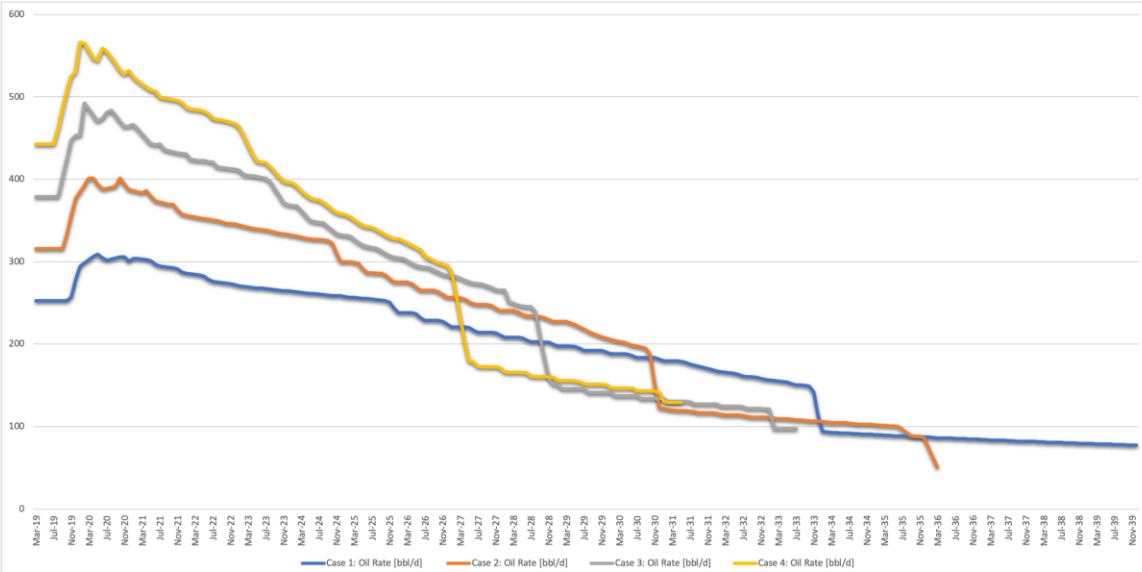


Figure 5-5 - Oil Production Rate vs Time

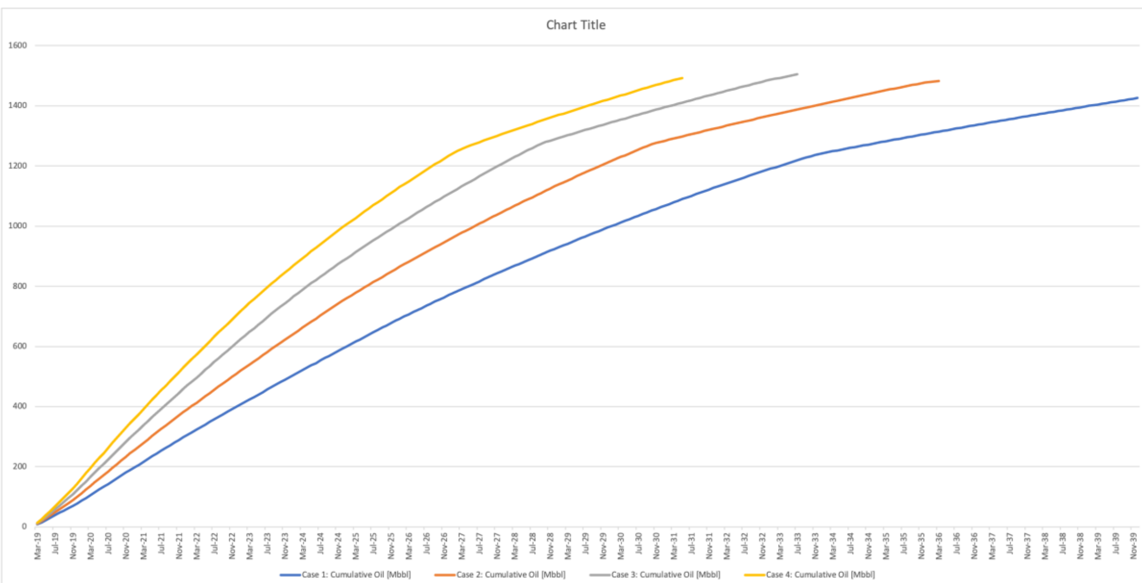


Figure 5-6 - Cumulative Oil Production vs Time

5.3 – Discussion

CO_2 is 3-9 times more soluble in oil than water, therefore results in higher oil displacement and recovery in compare to water **(Jian et al, 2019).** For the cases, when miscible CO_2 displacement method as used the oil production rate was high but as the method was alerted to water displacement the oil production started to decrease and the decreased further after the remining volumes of CO_2 miscible in the oil were produced. Also, similar to the study done by Holm and O'Brien **(1971)**, which showed that the recovery factor by CO_2 injection is higher than water as the injection increases from 53% to 82% the recovery factor the displacement method was changed to water injection only increased by 6% only. Miscible CO_2 injection leads to viscous fingering as CO_2 dissolves in oil, high amounts of CO_2 is produced and oil viscosity reduces, therefore WAG is used to control the mobility by increasing viscosity and density, which improves the sweep efficiency **(Hawez and Ahmed, 2014).** In addition, in order to maintain and increase the reservoir pressure CO_2 injection is used after water injection **(Aycaguer, Lev-On, and Winer, 2001: Beckwith, 2011: Han et al., 2016: Eliebiet al., 2017: Hamid et al., 2017: Seyyedsar, Ferzaneh, Sorhrabi, 2017)**. Therefore, in this study water is injected in the system continuously at constant rate for each case but the rate increases with increasing total fluid injection rate. In case 1 for 2000 rb/d the water injection rate was 95.2 bbl/d, while as the injection rate is increased to 3500 rb/d, case 4, the water injection rate is increased to 166.7 bbl/d. Additionally, for case 2 and 3 the water injection is 119 and 142.9 rb/d, respectively. In the study done by Hawez and Ahmed **(2014)** using Eclipse software for a 3D model based on carbonate reservoir, the study showed 44% oil recovery, quite similar to the prediction results by EORgui using the carbonate model used in this study, which showed overall recovery factor of 43% was the lowest value using injection rate of 2000 rb/d and the highest 45% with injection rate of 3000 rb/d. In the investigation done by Alshaibi, Ramadan, and Elsounousi **(2019)** using EORgui, sensitivity analysis was done to study the effect of injection rate and GOR on oil recovery. The results of their study are aligned with this study as both showed that with increasing injection rate the oil production increases. The results showed that the oil production increases as the injection rate is increased but the water injection rate to maintain the pressure also increases and the life of the reservoir well is shorted. The overall recovery rate for the injection rate 2000, 2500, 3000, and 3500 rb/d were 43%, 44%, 45% and 44.7%. The optimum injection rate is 3000 rb/d with overall oil recovery factor of 45% and cumulative oil production of 1504.8 Mbbl/d. Moreover, CO_2 breakthrough is the earliest for the highest injection rate and is the latest for the lowest injection rate by several months in compare to 3500 rb/d. In miscible CO_2 injection the displacement efficiency is improved due to the reduction of interfacial tension, which improves the oil recovery also **(Sira, Janna, and Le-Hussian, 2020).** This can be seen since as the CO_2 is injected after 7 months the oil recovery increases, this shows as the CO_2 starts to dissolve into the oil the interfacial tension reduces and more displacement oil is displaced. As the CO_2 dissolves with the CO_2 breakthrough occurs, but the oil production increases then decreases as the CO_2 production increases further, once the MMP is achieved the recovery factor increases slightly, which was previously explained by Lake **(2010)**. As result, the CO_2 injection stops and changed to water injection, CO_2 production rate decrease until no more dissolved CO_2 is further is produced with oil. However, for all the cases a significant amount of CO_2 injected was produced with oil, which showed that CO_2 introduced into the reservoir was significantly miscible with oil and the conditions for miscible CO_2 injection is obtained. For case 3 the cumulative CO_2 injection rate was 16555.24 MMscf/d and the cumulative production rate was 14022.54 MMscf/d.

Chapter 6 - Conclusion

In order to determine if the oil recovery method is successful oil recovery is determined to analyses and determine the amount of oil recovered using displacement. Oil recovery methods use different mechanisms to reduce the residual oil saturation and increase the oil recovery, such as decrease the interfacial tension, alert the viscosity, reduce the surface tension and miscibility approach. For miscible CO_2 injection the interfacial tension is reduced as miscibility is achieved. CO_2 injection is a promising enhanced oil recovery method that has been proven throughout the years using various test such as pilot test, numerical test, and laboratory test, and is also used in many fields. CO_2 is more soluble in oil in compare to water, which decreases the oil viscosity therefore WAG is used to aid the mobility and improve the sweep efficiency.

In this numerical experiment, similar results were predicted. The results show:

- Miscible CO_2 injection was found to be the most favourable enhance oil recovery method, leading by 78%.
- Once miscibility between the fluids is obtained the interfacial tension reduces, improves the displacement efficiency, oil production rate increases to 303.5 bbl/d.
- Miscible CO_2 injection is more effective than waterflooding, waterflooding contributed only by 6% in the overall recovery factor in all cases.
- Injection rate effects the oil recovery and breakthrough time, as the injection rate is increased the oil recovery increased. Overall oil recovery factor recorded was 43% for injection rate of 2000 rb/d, with cumulative oil production of 1425.88 Mbbls. On the other hand, the highest overall recovery factor was 45%, with cumulative oil production of 1504.84 Mbbls, recorded when injection rate of 3000 rb/d was used. While the breakthrough time is earlier, when the injection rate is increased. The earliest breakthrough time was recorded at the highest injection rate of 3500 rb/d, which in compare to 2000 rb/d was earlier by 3 months.

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Abstract - Arabic خلاصة

ينقسم إنتاج الهيدروكربونات إلى ثلاث مراحل وفقا لطريقة الإنتاج المستخدمة والوقت؛ انتعاش النفط الأولي، واستعادة النفط الثانوي، والثالثة / تعزيز انتعاش النفط. من أجل إنتاج النفط المتبقية في مكان وتستخدم أساليب مختلفة في الثانوية وتعزيز استعادة النفط. في هذه الورقة، سيتم استخدام فيضان ثاني أكسيد الكربون. حقن ثاني أكسيد الكربون هي واحدة من الطرق المذيبات الأكثر شيوعا المستخدمة، وذلك أساسا في الولايات المتحدة الأمريكية. ويؤدي حقن ثاني أكسيد الكربون إلى انخفاض في لزوجة النفط والتوتر بين الأعراق، مما يؤدي إلى تحسين نسبة التنقل والتشريد. في هذه الورقة، لتقييم استعادة النفط باستخدام حقنة ثاني أكسيد الكربون غير قابلة للخطأ EORgui **البرمجيات استخدمت. وقد تم وضع معايير للفحص من أجل التحقيق في طريقة الإزاحة المناسبة لبيانات الخزان المستخدمة. وكانت بيانات الخزان المستخدمة من خزان من إقليم كردستان، تديره شركة DNO. وتظهر النتائج أن**الحقن ثاني أكسيد الكربون غير قابل للخطأين يؤدي **مع 78٪ في المقام الأول. لذلك**،تم حقن WAG-CO_2 غير الصالحة للخطأ **في البئر. وأظهرت النتائج أن استعادة النفط تزداد مع** حقن ثاني أكسيد الكربون غير القابل للخطأ في الخزان ولكن مع تغيير الطريقة إلى حقن المياه يكون استعادة **النفط أقل. ومع ذلك، كان عامل الانتعاش العام 43.22٪. كما تم تحليل الحساسية لتحديد تأثير معدل حقن السوائل الكلي على استعادة النفط باستخدام ثلاث معدلات حقن مختلفة. وقررت النتائج أنه مع ارتفاع معدل الحقن في معدل إنتاج النفط والوقت الاختراقي في وقت سابق. تم تحديد أعلى عامل استعادة النفط باستخدام معدل حقن 3000 rb/d.**

Abstract - Kurdish پوختە

بەرهەمهێنانی هایدرۆکاربۆن دابەش دەکرێت بۆ سێ قۆناغ بەپێی شێوازی بەرهەمهێنان بەکارهاتووە و کات؛ چاککردنەوەی نەوتی سەرەتایی، گەڕاندنەوەی نەوتی دووەم، گەڕاندنەوەی نەوت بۆ بەرهەمهێنانی ئەو نەوتەی کە لە شوێنی خۆی ماوەتەوە، لە ناوەندی دا چەند میتۆدێکی جیاواز بەکار دەهێنرێ و چاککردنەوەی نەوت بەرز دەکاتەوە لەم کاغەزەدا لافاوی دوانەئۆکسیدی کاربۆن بەکاردەهێنرێت دەرزی ئۆکسیدی کاربۆن یەکێکە لە باوترین شێوازە کانی بەکارهێنانی ، بە شێوەیەکی سەرەکی لە ئەمریکا . دەرزی ئۆکسیدی کاربۆن دەبێتە هۆی کەمکردنەوەی ڕێژەی ڕۆنەوی و گرژی نێوان دەم و چاوی ، ئەمەش دەبێتە هۆی باشتر بوونی ڕێژەی جوڵە و جێگۆڕکێ . لەم کاغەزەدا بۆ هەڵسەنگاندنی چاککردنەوەی نەوت بە بەکارهێنانی نەرمامڕازیدەرزی ی CO_2 ئی ئۆ ئارگی بەکار هاتووە . پێوەری پشکنین بۆ لێکۆڵینەوە کرا، کە شێوازی جێگۆڕکێ بۆ داتای ئاوتکەی بەکارهاتوو گونجاوە. داتای ئاودانی بەکارهێنراو لە ئاوێکی ئاودا لە هەرێمی کوردستانەوە بووە، کە لەلایەن DNOبە هەڵە لە سەرەتادا 78 ٪ پێشی دەکرد CO_2 وە بەکارهاتووە ئەنجامەکان ئەوە نیشان دەدات کە دەرزی بۆیە، واگ-سیئۆ$_2$ بە هەڵە لە بیرەکەی دراوە ئەنجامەکان دەریان هێنا کە چاککردنەوەی نەوت زیاد دەکات بە . هۆی ئەوەی کە ئۆکسیدی ئۆکسیدی 2 بە هەڵە لە ناو ئاودا دەدریت بەڵام لە کاتێکدا کە ئەو شێوازە دەگۆڕدرێت بۆ ئاو لێدانی نەوت کەمتر دەبێت . بەڵام، کۆی هۆکار بۆ چاکبوونەوە43,22٪ بووە هەروەها شیکاری هەستیاری کرا بۆ دیاریکردنی کاریگەری ڕێژەی دەرزی شلەی گشتی لەسەر چاکبوونەوەی نەوت بە بەکارهێنانی سێ ڕێژەی دەرزی جیاواز . ئە نجامە کان دە یانخستە ر ئە وە ی ڕێژە ی دەرزی لێدان ڕێژە ی بە رهە مهێنانی نە وت زیاد بکات و کاتی سە رکە وت پێشکە ش کردن زووترە بەرزترین هۆکار بۆ گەڕاندنەوەی نەوت بە بەکارهێنانی ڕێژەی دەرزی 3000 رب/ دی دیاری کرا.