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Maximizing CO_2-EOR Potential for Carbonate Reservoir, Horus Field, Western Desert, Egypt

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Abstract

Horus Field whose main reservoir is Abu Roash "G" Dolomite, has been facing a decline in the production rates; however, it has managed to maintain a stable oil production plateau of 1050 barrels per day, with a significant water cut of 65%. This paper aims to investigate the efficiency of CO_2 EOR for the Horus field to identify the optimal approaches for maximizing oil recovery. An experimental study was employed using real core plug samples from the field. The setup was configured to mimic reservoir conditions at 70°C and 1200 psi, followed by injecting formation water, crude oil, and CO_2 to study primary drainage, secondary imbibition, and enhanced oil recovery (EOR). The study yielded results of achieving 0.59 PV oil saturation after primary drainage and further oil recovery through subsequent water flooding and CO_2 injection. The findings presented a promising opportunity into the behavior of the CO_2 in the carbonate reservoirs and its impact on oil recovery where the primary recovery methods produced 11.5 million barrels, representing a recovery factor of 19.6% of the OOIP. Water flooding increased the recovery factor to 23.7%, resulting in an estimated cumulative oil production of 14 million barrels. The increase in oil production from primary recovery to water flooding was 2.5 million barrels, representing a 21.7% improvement over primary recovery production. However, CO_2-EOR achieved a significant increase, with cumulative production reaching 22 million barrels and a recovery factor of 37.3%.

Introduction

CO_2 Enhanced Oil Recovery has emerged as a promising approach for increasing oil recovery rates, where it entails injecting carbon dioxide (CO_2) into mature oil fields, thus increasing the oil displacement and, as a result, the overall recovery factor. This strategy not only provides economic benefits, but it also coincides with environmental aims by utilizing and sequestering CO_2, hence, reducing greenhouse gas emissions. Oil production from tight reservoirs became feasible and cost-effective when any development strategy was adopted [1] . The Horus field is one of the largest oil-bearing tight formations in the western desert, with an estimated initial oil in place (IOIP) of 58 million barrels; nevertheless, long-term sustained oil production from tight formations is becoming a difficulty. Horus Field has been producing for a long period; however, it has been observed that its production rates are declining over time. Accordingly, enhanced oil recovery using CO_2-EOR shall be considered as a tertiary recovery method to maximize the extraction of the remaining resources. Hence, not only the reservoir's lifetime will be extended but also the existing field's profitability will be increased [2 , 3 , 4] .

Characteristics of Carbonate Reservoirs

Fractured carbonate reservoirs contain more than 60 % of the world's proven oil reserves, in addition to 40% of the trapped world's gas reserves. Although expanding oil and gas production from carbonate reservoirs isn't the only way to meet present energy demands, it's obvious that these reservoirs will play an increasingly important role in the petroleum sector. Carbonate reservoirs have a wider range of hydrocarbon productivity than the more prevalent sandstone reservoirs. Not only can these reservoirs provide the most prolific and sustained production rates but also it could be at the other extreme in terms of hydrocarbon production [5] .

Many carbonate reserves will not produce any oil or gas until they are artificially fractured. However, due to their complexity and heterogeneity, these reservoirs are regarded as extremely difficult to accurately anticipate recovery [6] . Carbonates are limestones, dolomites, and other carbonate rock minerals formed through precipitation [7] . Naturally fractured reservoirs hold a significant portion of the known hydrocarbons worldwide, in addition, they feature fractures that exhibit considerable permeability anisotropy. Ramirez et al [8] . stated that spontaneous fractures may improve the final recovery of a reservoir depending on the fracture zone's characteristics, for instance:

- High structural relief in a reservoir's vertical fractures promotes gas migration to the top for efficient oil gravity drainage [9] .
- Fractures can also cause reservoir channelization, resulting in an early breakthrough of water or gas in production wells [10 , 11] .

Challenges of Carbonate Reservoirs

Carbonate reservoirs, such as limestone and dolomite deposits, typically have more complicated pore structures and variability than sandstone reservoirs. These qualities can make oil recovery more challenging. For instance, the reservoir heterogeneity and fracture networks' complexity make it difficult to accurately model and characterize the reservoir, thus, it's difficult to predict the oil flow and the completion strategies [12] . In consequence, making it is technically challenging to map the subsurface geology and fracture systems. Moreover, the carbonate rock's low matrix permeability requires advanced drilling techniques and hydraulic fracturing making it challenging to achieve the required commercial production rate. Also, the carbonate reservoirs might contain corrosive fluids that might create operational and equipment integrity issues. Furtherly, the reservoir properties can be altered over time due to the diagenetic processes like dissolution and reprecipitation of carbonate minerals, which consequently affects the overall production strategies [1 , 4] .

Accordingly, CO_2 flooding is beneficial in such geological environments as it can penetrate and displace oil in microscopic, convoluted pore spaces seen in carbonate formations, where CO_2 reacts with carbonate minerals in the reservoir to produce carbonic acid [13] . This acid subsequently dissolves sections of the carbonate rock, potentially enhancing the reservoir's permeability and porosity. This technique may improve the channels through which oil can flow. However, care must be taken to manage the extent of this reaction to avoid excessive dissolution, which might lead to reservoir damage. Thus, the injection process must be constantly monitored and maintained.

CO_2 Flooding in Carbonate Rocks

EOR is used to recover residual oil in reservoirs where primary and secondary recovery technologies have reached their economic limits as displayed in Figure 1. While Figure 2 [10] shows the fluid saturations and EOR goal values for common light and heavy oil reservoirs, as well as tar sand. For light oil reservoirs, EOR is often used following secondary recovery operations, with an EOR goal of around 45% original oil in place (OOIP). Heavy oils do not respond well to primary or secondary recovery methods, hence EOR technologies account for the majority of production from these reservoirs [11 , 14] .

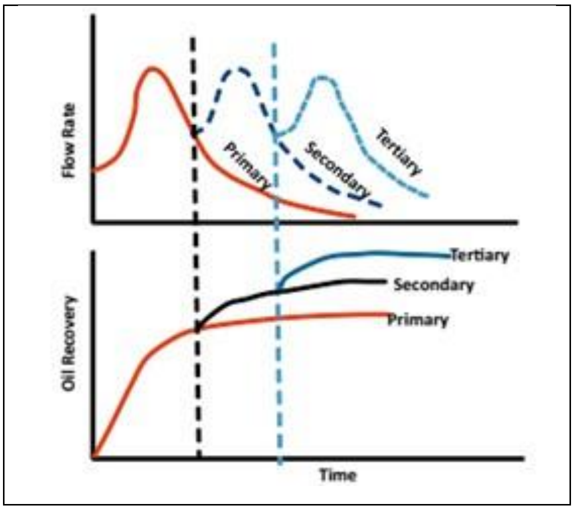

Figure 1 Oil recovery categories [10]

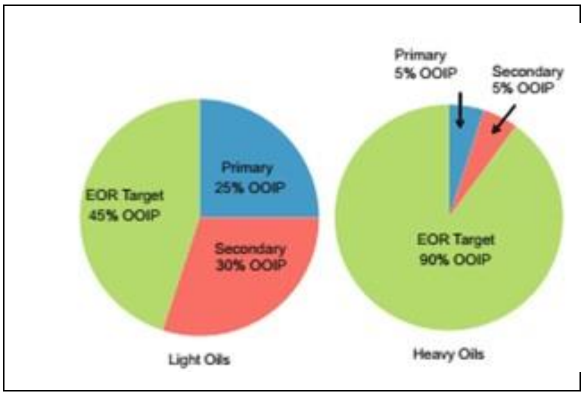

Figure 2 Target for different crude oil systems [10]

As a first stage in selecting and implementing an enhanced oil recovery method, a screening study should be done to determine the best EOR technology and assess its suitability for the reservoir. Ahmed [10] established screening criteria for improved oil recovery systems based on extensive data from EOR projects around the world, identifying the necessary reservoir and oil parameters for a successful EOR project in a specific field, as shown in Table 1 [15 , 16 , 17] .

Table 1 Summary of screen criteria for EOR methods [10]

Process	Crude Oil	Reservoir
N2 and flue gas	>35° API	So>40%
	<1.0 CP	Formation: SS or carbonate with few fractures
	High percentage of light hydrocarbons	Thickness: relatively thin unless formation is dipping
		Permeability: not critical
		Depth> 6000 ft
		Temperature: not critical
Chemical	>20° API	So>35%
	<35 CP	Formation: SS preferred
	ASP: organic acid groups in the oil are need	Thickness: not critical
		Permeability > 10 md
		Depth 9000 ft (function of temperature)
		Temperature <200° F
Polymer	>15° API	So>50%
	<100 CP	Formation: SS but can be used in carbonates
		Thickness: not critical
		Permeability> 10 md
		Depth < 9000 ft
		Temperature<200° F
Miscible CO2	>22° API	So>20%
	<10 CP	Formation: SS or carbonate
	High percentage of intermediate components (C5-C12)	Thickness: relatively thin unless dipping
		Permeability: not critical
		Depth: depends on the required minimum miscibility pressure "MMP
First-contact miscible flood	>23° API	So>30%
	<3 CP	Formation: SS or carbonate with min fractures
	High Cm	Thickness: relatively thin unless formation is dipping
		Permeability: not critical
		Depth> 4000 ft
		Temperature: can have a significant effect on MMP
Steam flooding	10-25° API	So>40%
	<10,000 CP	Formation: SS with high permeability
		Thickness > 20 ft
		Permeability>200 md
		Depth < 5000 ft
		Temperature: not critical
In situ combustion	10-27° API	So>50%
	<5000 cp	Formation: SS with high porosity
		Thickness > 10 ft
		Permeability > 50 md
		Depth < 12,000 ft
		Temperature > 100 °F

Carbon Dioxide Displacement Mechanisms

The solubility of CO_2 in oil is an important component in improving oil recovery [13] . This is induced by the mechanisms listed below:

1) Decreased oil viscosity and increased water viscosity
2) Crude oil swelling and reduced density
3) Acidic action on carbonates
4) Miscibility effects

When CO_2 is dissolved in oil, the oil viscosity is lowered significantly, whereas according to Simon and Graue [18] reduction in viscosity is a function of saturation pressure. Figure 3 demonstrates that the reduction in oil viscosity and increase in water viscosity leads to a decreasing mobility ratio.

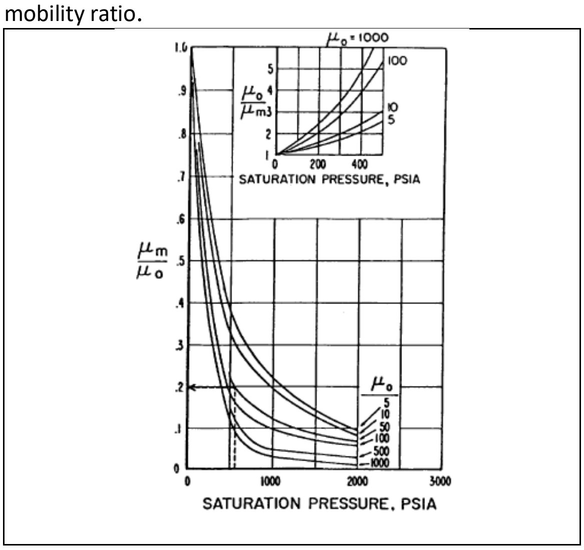

Figure 3 Reduction in water viscosity [18]

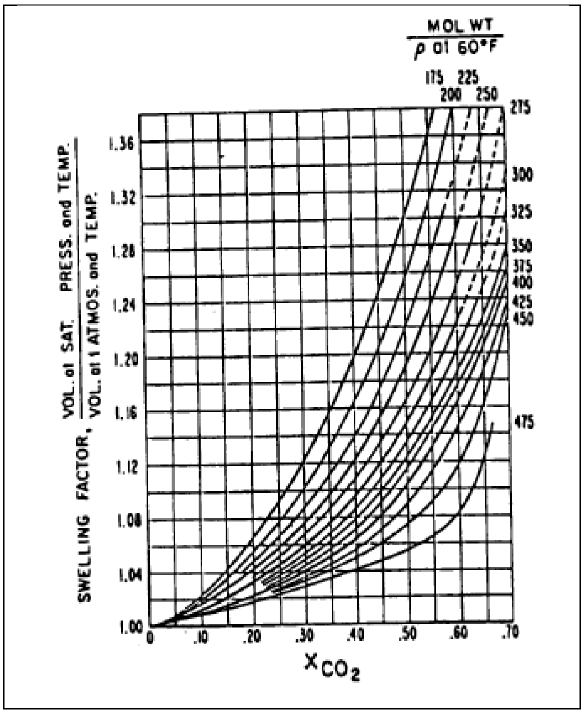

Figure 4 CO2 swelling factor [18]

In addition, dissolving CO_2 lowers the viscosity and increases crude oil volume, Figure 4 illustrates the relationship between the oil swelling factor, CO_2 mole fraction, and oil molecular weight. Oil swelling improves oil recovery by reducing the remaining oil saturation [19 , 20 , 21]

CO_2 Miscibility Effects Mechanisms

There are two approaches for achieving miscibility between any two fluids. Miscibility can occur during both first and multiple contacts when two fluids combine into a single phase and can entirely displace one another. However, this requires a certain level of pressure. First contact miscibility is when two fluids become one phase immediately, regardless of their proportions [22 , 23] CO_2 is often a multiple contact miscible, but can potentially be first contact miscible at high pressures. Multiple contact miscibility refers to the continuous transfer of oil and carbon dioxide components, resulting in oil saturated with CO_2 that is indistinguishable from CO_2 saturated with oil [24 , 25].

According to Zick [26] This process involves both condensation and vaporization, where CO_2 condenses into the oil, making it lighter, while the lighter components evaporate into the CO_2 gas phase, making it denser. This process continues until the two phases become united as illustrated in Figure 5 [27 , 28]

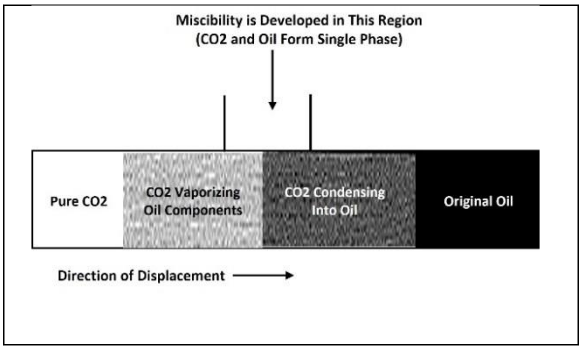

Figure 5 CO_2 displacement Mechanism [29]

Minimum Miscibility Pressure

1. Miscibility between oil and CO_2 is discovered to be temperature and pressure dependent. In a constant temperature reservoir, increasing pressure causes more CO_2 to dissolve in the oil [30]. The "Minimum Miscibility Pressure (MMP)" refers to the pressure when oil and CO_2 become miscible. Yellig et al [17] conducted slim tube tests shown in

Figure 6 illustrates the impact of CO_2 displacement pressure on oil recovery. The recovery rate increases with pressure and plateaus at MMP. An increase in pressure over MMP does not affect recovery. Horus reservoir is characterized as a 1D, homogeneous system with constant pressure [31] .

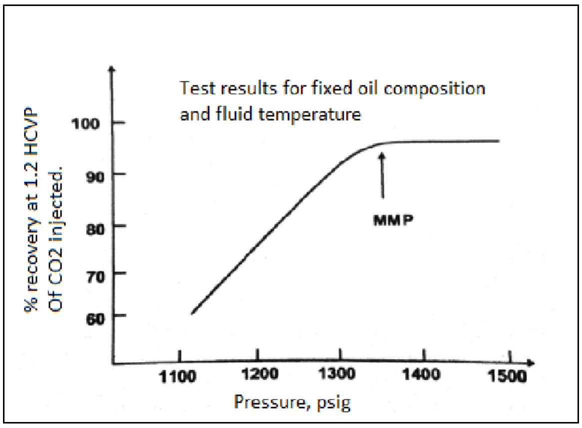

Figure 6 CO_2 Minimum Miscibility Pressure [32]

CO_2 is considered miscible with oil when its density is high enough to shift C5+ to C30 components from the oil phase to the vapor phase with a density range of 0.4 to 0.6 g/cc [25] . Furthermore, the MMP of C5+ components in crude oil varies with temperature, pressure, and molecular weight as shown in Figure 7 [24 , 25] .

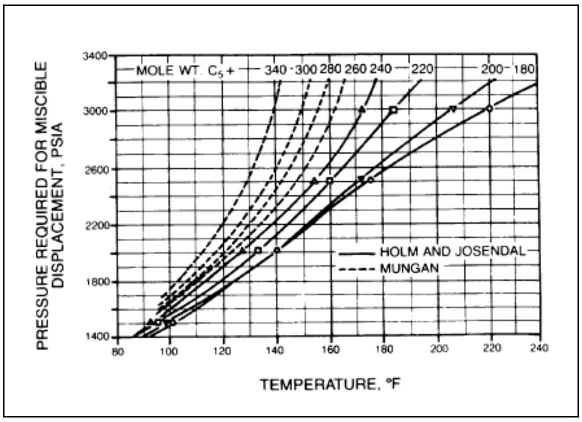

Figure 7 Holms and Josendal MMP [24] as function of temperature and Mw. Of C5+

Mitigation Strategies for CO_2 Flooding

Co_2 flooding processes improve both sweep efficiency and displacement efficiency, which are critical for evaluating CO_2's effectiveness in mobilizing oil. Mitigations to address reservoir heterogeneity have been developed. Advanced reservoir characterization techniques, such as 3D seismic imaging, core sampling, and well logging, offer detailed insights into the reservoir's structure. Simulation tools can predict fluid behavior and optimize injection strategies. Mobility control methods, such as water-alternating-gas (WAG) injection or the use of chemical additives, can improve CO_2 sweep efficiency and delay CO_2 breakthrough. Monitoring reservoir conditions and controlling injection parameters are essential for managing rock-fluid interactions. Additionally, technologies that optimize CO_2 capture can reduce costs and improve the efficiency of CO_2 utilization, enhancing the economic viability of such projects [32] .

Considering previous studies on CO_2 Enhanced Oil Recovery (EOR), CO_2-EOR is proposed for the Horus field to address the declining production rates and the significant increase in water cut due to reservoir depletion. Co_2 EOR aims to increase the field's oil recovery factor, improve sweep efficiency, and reduce oil viscosity. However, to fully realize its benefits, it is crucial to address environmental and economic challenges through careful planning and proactive management strategies. This approach ensures that CO_2 flooding projects can be successfully and sustainably implemented. This paper focuses on comparing oil recovery rates using traditional water flooding versus CO2 EOR. The study uses real core plug samples from reservoirs and replicates reservoir conditions to assess methods effectiveness.

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Methodology

A detailed experimental study was conducted using real core plug samples taken directly from the Horus field's Abu Roach "G" dolomite formation as follows:

Sampling

A core sample from well H-2 in the Horus field was carefully chosen for this study to fairly represent the Abo Rawash G Dolomite, a carbonate reservoir. After the extraction procedure, plugs were drilled from the original core slabs, and every sample was thoroughly cleaned and dried as shown in Figure 8. The core average porosity is 31%, whereas the typical permeability is 85 md and water saturation is 0.28. The samples diameter and length are 3.515 cm and 6.955 cm respectively, the volume is 67.45 ml (cm^3).

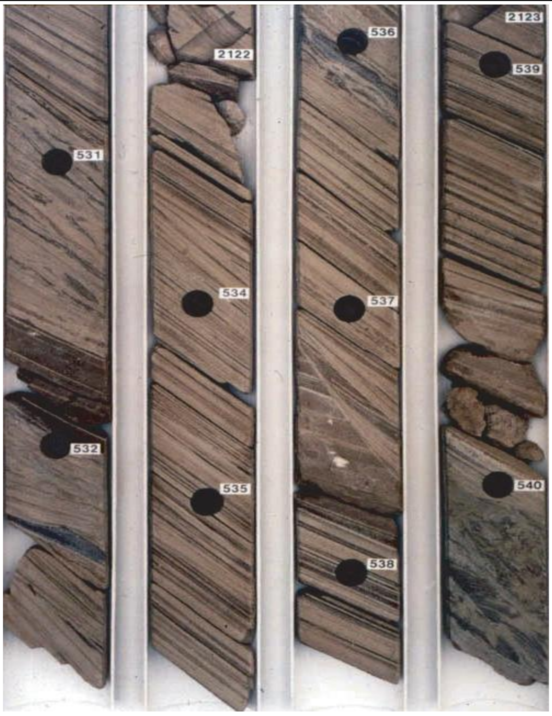

Figure 8 Core slap

Experimental Study Setup and Core Preparation

The core preparation was configured as follows:

1) To simulate reservoir temperature, the oven was maintained at 70°C.
2) The core plug was inserted into a case elastomer tube housing and secured with a solid stainless-steel extension within the core holder.
3) The core holder was positioned inside the oven. The other components including the two-syringe pump, graduated cylinder, back pressure valve regulator, and syringe pump, were positioned outside the oven. It was ensured that the oven was completely closed during the experiment. The core's dimensions, porosity, and weight were assessed before placing a porous plate at one end.
4) The core and porous plate were wrapped with PTFE tape, followed by aluminum foil strips, and then inserted in the core housing, followed by the core holder as shown in Figure 9.
5) The core holder was placed in the oven to bring it up to operating temperature. The core and system were vacuumed for an hour. A confining pressure of 1200 psi was applied with a syringe pump. The entire system was allowed to heat up to the operational temperature of 70°C, to simulate reservoir temperature.
6) The graduated cylinder is filled with core plug volume 67.45 ml (cm^3) and added 10% excess volume to be 74.7 ml.

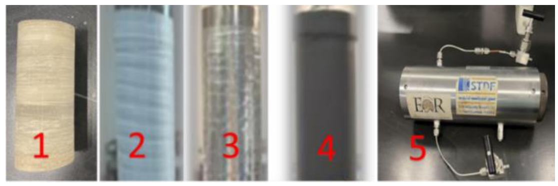

Figure 9 Core preparation steps

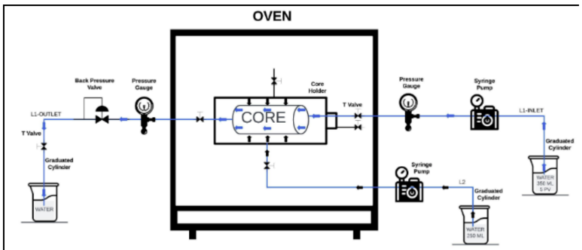

Figure 10 Experimental setup

Figure 10 represents the experimental setup of the equipment used in this study, it includes:

1. L1-INLET Pathway:
   - This pathway passes through the oven.
   - The configuration consists of a graduated cylinder connected to a syringe pump containing 350 ml of water at 5 pore volumes (PV) outside the oven.
   - At the end of the inlet, there is a pressure gauge valve.
   - A T pressure fitting valve connects to the core holder.
2. L1-OUTLET Pathway:
   - This pathway is connected to a pressure gauge valve followed by a back-pressure regulator.
   - The outlet then connects to a graduated cylinder.
3. Inside the Oven:
   - The core holder is connected to L2.

- L2 is connected to a T valve pressure followed by a syringe pump, which is connected to a graduated cylinder of water containing 250 ml of water outside the oven.

The experiment procedure:

1. Air Introduction:
   - Air is introduced into the entire system to ensure it is airtight.
   - This process displaces any fluids that may have accumulated within the system lines from earlier tests.
   - Any fluid collected from the core holder is gathered in the graduated cylinder.
2. System Vacuuming:
   - The entire system is vacuumed by connecting a vacuum pump to the core holder inlet cap.
   - The vacuuming continues until both pressures P1 and P2 approach zero.
3. Core Plug Preparation:
   - The core plug is placed into the oven.
   - L1-INLET and L1-OUTLET caps are attached to two pressure transducers to record P1 and P2.
   - These pressures are adjusted to match the current reservoir pressure.
4. Pressure Regulation:
   - The core holder outlet cap is maintained at 1200 psi using a back-pressure regulator.

This setup ensures accurate measurement and control of pressures within the system during the whole experiment.

Water Saturation

1) A syringe pump was used to inject water at a constant rate of 10 ml/min into the L2-INLET of the core holder, as shown in Figure 11.
2) To apply confining pressure over the core holder, water was filled to surround the core holder. The confining pressure was adjusted to 400-500 psi to avoid fracture pressure.
3) The pressure gauges of both the inlet and outlet were frequently checked to ensure pressure stabilization.
4) The experiment started by passing 350 ml of formation water at 5 pore volumes (PV) until making sure that the core was fully saturated with water. During this process, the pressure difference (delta P) was monitored to avoid fracture pressure.
5) The water passed through L1-INLET to L1-OUTLET.
6) After reaching 5 PV of formation water, the formation water was replaced with crude oil to start the primary drainage.

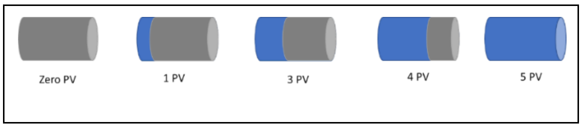

Figure 11 Formation water injection through the core

Primary Drainage

Table 2 Primary Drainage phases

	Phase 1
1)	The primary drainage started by injecting crude oil from the inlet and passing through the core plug to the outlet.
2)	The injection of crude oil continued until the reservoir's current status of 0.59 pore volumes (PV) of oil into the rock was reached.
3)	It was essential to account for all dead volumes in the lines and pumps before injecting oil into the core holder.
	Phase 2
1)	A graduated cylinder was filled with 74.7 ml of crude oil to start the primary drainage.
2)	The syringe pump had a dead volume of 20 ml, and the lines had a dead volume of 3 ml.
3)	The inlet graduated cylinder had 10 ml of crude oil remaining, while the outlet graduated cylinder had 2 ml of crude oil remaining. Therefore, the remaining 39.79 ml of oil in the core corresponded to 0.59 PV of the core volume of 67.45 ml.
4)	This results in a water saturation (S_{wi}) of 0.41 and an oil saturation (S_{oi}) of 0.59, representing the current status of the well before starting secondary imbibition and enhanced oil recovery (EOR).

Water Flooding / Secondary imbibition

After reaching the current reservoir pore volume of 0.59 PV oil which means 39.79 ml of oil is remaining in the core, secondary imbibition was initiated. Formation water was injected into the inlet at a flow rate of 10 ml/min, passing through the core holder until it reached the outlet. The experiment continued until the graduated cylinder was checked and no additional oil was generated. This step revealed that 30.35 ml of oil was still in the core and 9.44 ml was produced in the graduated cylinder from oil volume 39.79 ml. The current status of the well after secondary imbibition is characterized by a water saturation (S_w) of 0.55 and a saturation oil ratio (S_{or}) of 0.45. This indicates that the secondary imbibition process resulted in 0.45 PV of oil recovery.

EOR/CO2

This step involved injecting CO_2 at a pressure of 1200 psi into the inlet at a flow rate of 10 ml/min, passing through the core holder until it reached the outlet. The CO_2 EOR process started with 0.45 PV of oil still in the rock (30.35 ml) and the experiment continued until the graduated cylinder was checked and no additional oil was generated. The results of this step revealed the recovery of 13.35 ml of oil in the graduated cylinder at the outlet and considered a 2 ml of oil as dead volume. Consequently, the effective EOR was achieved as 11.35 ml of oil recovered from the total oil volume existing in the core (30.35 ml) which is 0.45 PV, resulting in the EOR efficiency is 0.37. Thus, signifying the

highest successful improvement to the overall oil production from
The reservoir.

Results and Discussion

The field was discovered in March 1982 and the initial oil in place, computed using Eclipse, was 58 million STB. The recovery factor for the depletion reservoir (Horus field) is 19.6%, which results in a reserve of 12 million STB that can be produced from primary recovery. The initial water saturation (S_{wi}) and initial oil saturation (S_{oi}) were respectively 0.13 and 0.87. After forty-two years of production the water saturation and residual oil saturation (S_{or}) were 0.41 and 0.59 respectively.

The core plug volume is 67.45 ml; Therefore, the 0.59 PV of core volume is oil which equal 39.79 ml. After the secondary imbibition (water flooding) which started with 0.59 PV of oil saturation and after injecting formation water the phase was finished with 0.45 PV of oil in core (30.35 ml). Moreover, the CO_2 EOR flooding started with 0.45 PV of oil in the core plug. After finishing the CO_2 phase, the remaining oil was 0.28 PV (19 ml).

To sum up, the water flooding scenario resulted in an increase in the recovery factor (R.F.) from 19.6% to 23.7%, which is 4.1% higher than the base case (DNC) or 2.5 million barrels more. In addition, introducing the CO2-enhanced oil recovery (CO_2-EOR) significantly increased from 23.7% to 37.3% in comparison to the water flooding scenario. Surprisingly with a recovery factor of 37.3%, the CO_2-EOR scenario showed the largest improvement in oil recovery. CO_2-EOR demonstrated the most incremental increase of 11 million barrels between the two scenarios as compared to the DNC scenario as shown in Table 3.

Table 3 Cumulative results of all scenarios in the lab

Case Name	Cumulative @29 Oct 2045	R.F %	Incremental over DNC
DNC	11.5 million Bbl.	19.6%	-
Water flooding	17 million Bbl.	29.4%	5.5 million Bbl.
CO_2-EOR	21 million Bbl.	35%	9.5 million Bbl.

Table 4 Cumulative results of all scenarios in simulation

Case Name	Cumulative	R.F %	Incremental over DNC
DNC	11.5 million Bbl.	19.6%	-
Water flooding	14 million Bbl.	23.7%	2.5 million Bbl.
CO_2-EOR	22 million Bbl.	37.3%	10.5 million Bbl.

Table 4 demonstrates the results of the prior simulation study that investigated the effectiveness of CO_2 injection as an enhanced oil recovery (EOR) technique for maximizing oil extraction from reservoirs, with a special focus on Horus Field using simulation models. The three scenarios that determined the most effective method for increasing oil recovery that published in the paper Exploring CO_2-EOR miscibility flooding potential Youssef et al. 2024.

Figure 12 and Figure 13 bar plot compares the results of the cumulative production and recovery factor for different Enhanced Oil Recovery (EOR) methods when performing lab tests and using simulation software showing the cumulative Production million Bbl.)(.): Represented by the light blue bars and the recovery Factor (%): Represented by the light green bars.

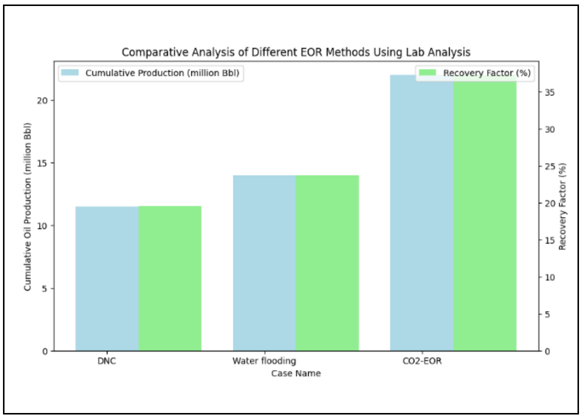

Figure 12 Comparative Analysis of Different EOR Methods in Lab

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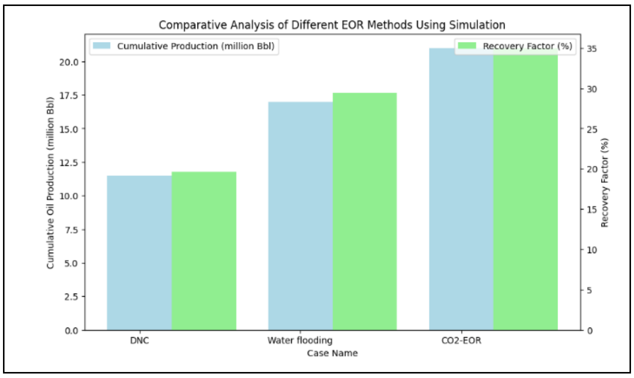

Figure 13 Comparative Analysis of Different EOR Methods in Simulation

Table 5 and Figure 14 show a comparative analysis between the results of water flooding and CO_2 flooding based on lab studies and simulations, where both analyses show significant improvements in oil recovery with CO_2-EOR, but the lab results suggest a slightly better performance in terms of both cumulative production and recovery factor. This may be due to controlled experimental conditions that Favor CO_2-EOR processes or specific characteristics of the core samples used.

Table 5 Comparative Analysis of Water and CO_2 Flooding in Lab and Simulation

Comparative Analysis	WF		CO_2	
	Lab	Sim.	Lab	Sim.
Increase in Cum. Oil Prod.	21.7%	47.8%	91%	82.6%
Total Prod.	14 million bbl.	17 million bbl.	22 million bbl.	21 million bbl.
R.f.	23.7%	29.4%	37.3%	35%

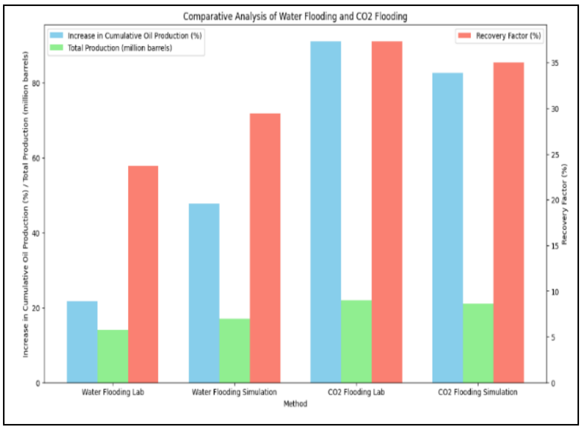

Figure 14 Comparative Analysis of Water and CO_2 Flooding in Lab and Simulation

Figure 14 shows the comparative analysis of water flooding and CO_2 flooding based on lab studies and simulations:

- Increase in Cumulative Oil Production (%): Represented by the light blue bars.
- Total Production (million barrels): Represented by the light green bars.
- Recovery Factor (%): Represented by the salmon-colored bars.

In addition a comparative analysis between the simulation-based study and the experimental study emphasizing the key findings shown in Figure 15 and Figure 16 which demonstrates a comparison between the recovery factor results and the cumulative oil production rates of both lab and simulation results resulting in the following:

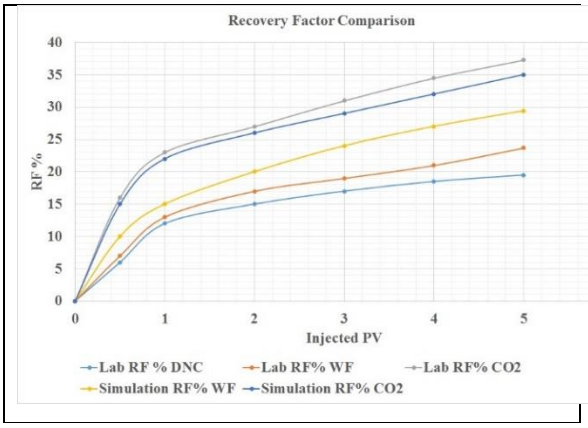

Figure 15 Recovery factor comparison between lab test and simulation study

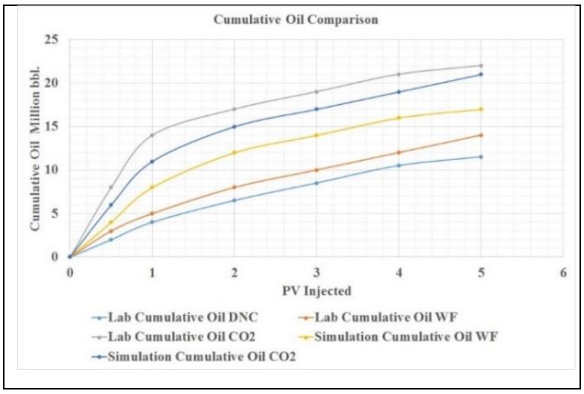

Figure 16 Cumulative oil comparison between lab test and simulation study

The comparison between lab test analysis and simulation models showed that simulations generally showed higher increases in cumulative oil production compared to lab studies for both water flooding and CO_2 injection. This suggests that simulations may better predict or optimize recovery processes, possibly due to more precise modeling of reservoir conditions and operational parameters. While lab studies sometimes show higher recovery factors (especially evident in CO_2 injections), simulations provide more consistent performance across different recovery methods. This highlights the potential of simulations in refining recovery strategies and predicting outcomes under varying conditions.

Moreover, both Lab and simulation methods show an increase in recovery factor, the simulation analysis tends to predict more optimistic outcomes for water flooding, whereas the laboratory analysis slightly favors CO_2-EOR. These differences highlight the importance of using both lab experiments and simulations to comprehensively evaluate EOR techniques. The data strongly suggest that CO_2-EOR is the most effective technique for maximizing oil recovery in the Horus Field, surpassing the performance of water flooding. This is evidenced by higher cumulative oil production and recovery factors in both experimental and simulation analyses. Implementing CO_2-EOR could therefore lead to more efficient and profitable oil extraction from the reservoir.

Conclusions and Recommendations

The current paper assesses the CO_2 -EOR flooding on oil recovery in the carbonate reservoir of the Horus field, western desert, Egypt. The study entailed a comprehensive analysis of CO_2-EOR'S impact on oil recovery, For Horus Field, the study demonstrated in the lab showed that water flooding and CO_2-EOR are the most effective techniques for increasing oil recovery as follows:

- Water flooding increased cumulative oil production by 21.7%, reaching 14 million barrels with a recovery factor of 23.7%.
- CO_2-EOR demonstrated the most significant increase, with a cumulative production of 22 million barrels and a recovery factor of 37.3%.
- CO_2 injection is a promising technique for improving oil recovery with a significant improvement in both the recovery factor and the oil production rate.
- To ensure higher scalability, it is crucial to evaluate the technical, economic, and environmental feasibility of CO_2-EOR technologies.
- To optimize CO_2 injection, it is vital to understand the geological and petrophysical reservoir parameters like structure, porosity, and permeability.
- The comparison between lab test analysis and simulation models showed that simulations generally showed higher increases in cumulative oil production compared to lab studies for both water flooding and CO2 injection.
- The simulation analysis tends to predict more optimistic outcomes for water flooding, whereas the laboratory analysis slightly favors CO2-EOR.
- The data strongly suggest that CO2-EOR is the most effective technique for maximizing oil recovery in the Horus Field, surpassing the performance of water flooding. This is evidenced by higher cumulative oil production and recovery factors in both experimental and simulation analyses.

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Conflicts of interest

There is no conflict of interest on behalf of all authors

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