Experimental Study on Enhanced Oil Recovery: Utilizing CO2 Injection forReservoir Revitalization

Halilat Israa[1], Zeddouri Aziez[2], Belksier Mohamed Salah[3]

[1,2;3]Laboratory of underground reservoirs of hydrocarbon, gaz and aquifers.University of Kasdi Merbah Ouargla,Algeria.

Corresponding author: Zeddouri Aziez (zeddouriaziez@yahoo.fr).

Recieved : 25/11/2023 Accepted : 05/02/2024 Published : 29/02/2024

Abstract

Over the past decades, billions of dollars has been invested by the oil industry in researching and developing enhanced oil recovery (EOR) technologies to recover remaining oil. One of the most promising technologies developed is based on injecting CO2 into existing oil wells to produce ever-smaller amounts of crude oil. The latter, which is difficult to obtain, will react with carbon dioxide, at reservoir high pressures and temperatures, through a number of mechanisms, including interfacial tension (IFT) reduction, oil swelling, viscosity reduction and light hydrocarbon extraction. These mechanisms may play a more important role in enhancing oil recovery, based on whether the CO2 displacement is miscible or immiscible. Like for instance,in miscible condition, IFT reduction and oil viscosity reduction play more vital roles in CO2- EOR. Additionally, CO2 has the capability of invading zones not previously invaded by water, as well as releasing and reducing trapped oil to flow more freely into an old well and reviving its production.

In this study we focused on the miscible CO2 injection process as an effective and widely used method for improving oil recovery, and based on the characteristics of the Hassi Messaoud reservoir, We prepared corresponding synthetic cores with similar properties (clay sandstone from the upper Triassic), which we heated to a temperature of 70C◦. In the realized experiment, we demonstrated the effectiveness of miscible CO2 injection applied to multiple samples by calculating the effective permeability of artificial cores through the falling tip permeability set and then using “oil/water and gas” constant pressure system and inject carbon dioxide under different conditions (pressure and temperature) to extract residual oil. Thus, experimental resultsshow that residual oil from the Hassi Messaoud field can be extracted by injecting carbondioxide at a pressure of 28 bar and at a temperature of 70C◦ in the laboratory, increasing the remaining oil yield up to 10 % for low permeability and light oil tanks to conclude that carbon dioxide is one of the best methods for residual oil recovery.

Key Words:-CO2-EOR ; Residual oil ; Falling head permeability Set ; Constant pressure system (oil /water) ;Relative permeability.

Tob Regul Sci.™ 2024;10(1): **1322 - 1336**

DOI: doi.org/10.18001/TRS.10.1.84

Introduction*:*

Algeria's hydrocarbon production is in sharp decline after peaking in 2007 (1.38 million barrels per day). To date, the crude oil produced in Algeria is from onshore fields. Algeria is struggling to manage a sharp decrease in energy revenues and to revive oil fields that have been declining for almost a decade. Nearly all production to 2020 comes from fields with discovery dates prior to 2000. Production from these fields is expected to descend by nearly 50% by 2030 and 92% by 2050 [1, 2].

The development of reservoirs and the production of crude oil to three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. But only about 10 percent of a reservoir's original oil in place is typically produced during primary recovery. Secondary recovery techniquesextend a field's productive life generally by injecting water or gas to displace oil and drive it to a production wellbore, resulting in the recovery of 20 to 40 percent of the original oil in place [3, 4]. However, with much of the easy-to-produce oil already recovered, producers have attempted several tertiary, or enhanced oil recovery (EOR), techniques that offer prospects for ultimately producing 30 to 60 percent, or more, of the reservoir's original oil in place. Three major categories of EOR have been found to be commercially successful to varying degrees: thermal recovery, chemical injection and gas injection [5, 6].

Amid all enhanced oil recovery (EOR) methods, gas injection processes have been identified as one of the most efficient techniques. On the other hand, gas injection can enhance oil recovery by interfacial tension (IFT) reduction due to mass transfer between the displaced and displacing phases during vaporizing/condensing gas drive, oil swelling, and oil viscosity reduction leading to reservoir repressurization and alleviation of capillary forces [6, 7].

CO_2 flooding in low permeable and light-oil reservoirs, as it can increase recovery factor from 10 to 20%. Moreover, it reduces atmospheric gas emissions through CO_2 storage. Gas miscible flooding implies that the displacing gas is miscible with reservoir oil either at first contact or after multiple contacts, which in turn improve the volumetric sweeping and displacement efficiencies (E_v and E_d) respectively. A transition zone will develop between the reservoir oil and displacing gas, where the miscibility of the injected gas depend on reservoir pressure, temperature, and oil properties [8].

Miscible flooding depends on mobilizing the oil light components, reduction of oil viscosity, the vaporization and swelling of the oil, and the lowering of interfacial tension. The injected CO_2 completely dissolve through crude oil at the minimum miscibility pressure (MMP) which determined experimentally through slim-tube tests or by mathematical correlations and defined as, the pressure at which more than 80% of original oil-in-place (OOIP) is recovered at CO_2 breakthrough. However, on an industrial scale, an oil recovery of at least 90% at 1.2 pore volume of CO_2 injected is used as a rule-of-thumb for estimating MMP. When the reservoir pressure is above the MMP, miscibility between CO_2 and reservoir oil is achieved through multiple-contact or dynamic miscibility, where the intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO_2 (vaporized gas-drive process) and part of the injected CO_2 dissolves into the oil (condensed gas-drive process). This mass transfer between the oil and CO_2 allows the two phases to become completely miscible without any interface and helps to develop a transition zone that is miscible with oil and CO_2. CO_2 miscible flooding comprises first contact; vaporizing gas drive, and condensing gas drive [9]. First contact consists of mixing miscible solvents with reservoir oil in all proportions and the mixture remains in one phase. Either through single or multiple contacts and resulting in much improved oil recovery. The vaporizing gas-drive process (high-pressure gas drive) achieves dynamic miscibility by in situ vaporization of the intermediate-molecular-weight hydrocarbons from the reservoir oil through injection of lean gases or CO_2. The condensing gas-drive process (enriched gas drive) achieves dynamic miscibility by in situ transfer of intermediate molecular weight hydrocarbons from rich solvent to lean reservoir oil through condensation process [9].

In our study, the enhanced oil recovery of carbon dioxide was used on artificial samples that simulate the nature of Hassi Messaoud field and the different in terms of cumulated dry weight for the purpose of knowing the possibility of extracting the remaining oil for this field and its production capacity. This difference is the result of pore size distribution, pore positioning and their relationship to each other (the difference in porosity).

We also realize that the relative permeability is important for estimating the flow of reservoir fluids, as is the case for the interfacial tension (IFT), so the (IFT) decreases with an increase in relative permeability, which is of great importance for the improved oil recovery operations such as the methods of miscible gases, so that we pumped carbon dioxide to reduce the interfacial tension (IFT) ,reducing the viscosity of the oil ,this leads to decreased capillary forces, and this study was discussed by using the appropriate pumping pressure (constant pressure system) and a temperature of 70C°, and finally the volume of the oil extracted from the experiment was measured.

Materials and experimental methods

In this paper, we have studied the enhanced oil recovery by carbon dioxide pumping for extraction residual oil in reservoir through an experiment applied on artificial samples adapted to the nature of the Hassi Messaoud reservoir [10, 11, 12].

The experiment workflow (Figure 1) was represented by the application of several steps which are: (1) Granulometric tests (Sieving), (2) Artificial samples, (3) Falling Head permeability test,

(4) Constant pressure system (oil /water), (5) Water injection and (6) CO_2 injection.

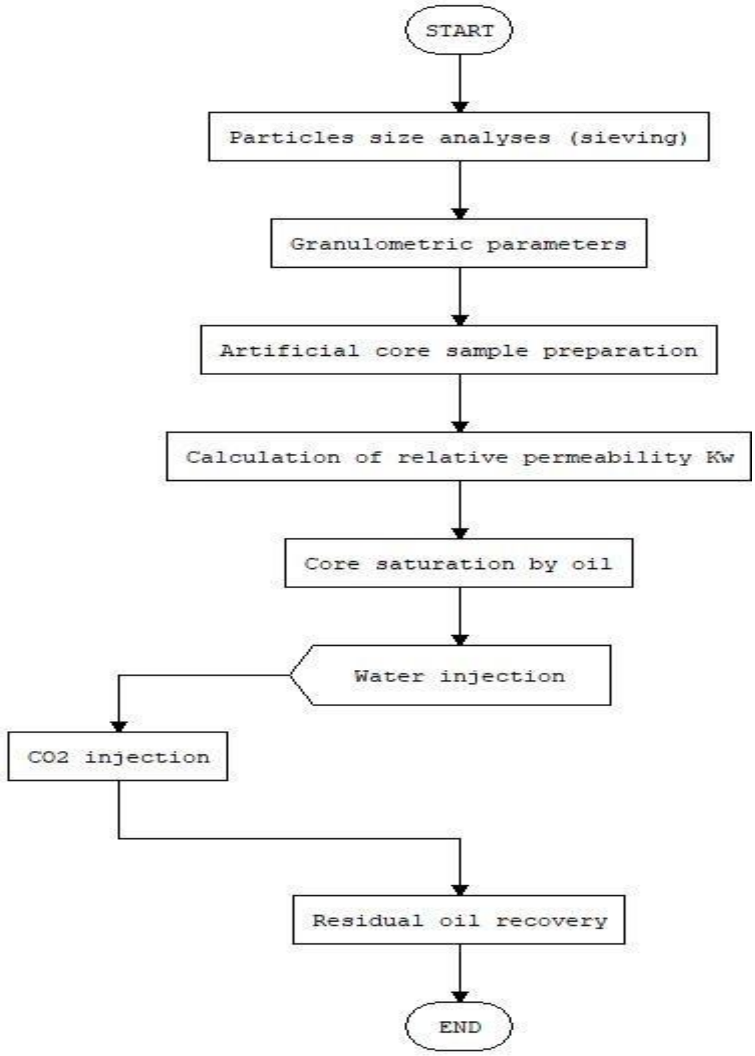


Figure 1. Flowchart of the experimental study

Artificial Core samples preparation (Granulometric tests by Sieving)

The particle size analysis must make it possible to separate the grains from an aggregate and to classify them by diameter. The mesh size of the sieves defines these classes [13].

The objective of the test is To determine the quantity (mass) of grains per diameter up to 2mm. We sieved 10 kg of sand similar to the Hassi Messaoud reservoir and divided it into five samples (S1, S2, S3, S4 and S5), each one differing from the other by its cumulated dry weight to obtain core samples with different permeability. Before this step we determined the dry mass of this latter.

The test aims also to estimate the permeability by suggesting a granular measurement method and testing its efficiency through Method of permeability determination for soils wide grain size (Kozeny's formula) [14], If we do not know the effective porosity, we can write, noting that the porosity of silts and sands is $0.286 < n < 0.5$ and considering that the effective porosity is, for sands and silts, about of 20% of the total porosity. The formula is written: K"G"=α(5/(1/d10+1/d30+1/d50+1/d70+1/d90)) [15]

With: $0.25 < \alpha < 2.8$

di: diameter in centimeters of the grain corresponding to a refusal of i %. kG : permeability estimated from grain size analysis.

The figure (2) represents grain size distrubution by sieving of the 5 samples.

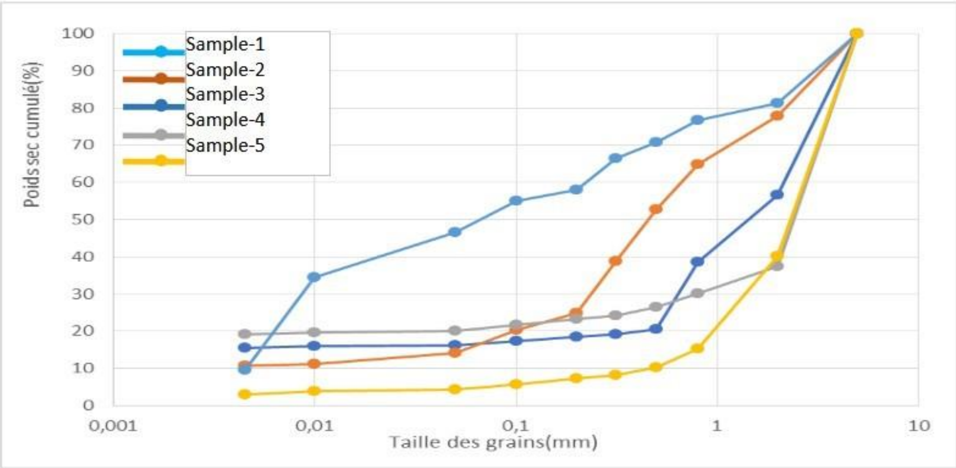
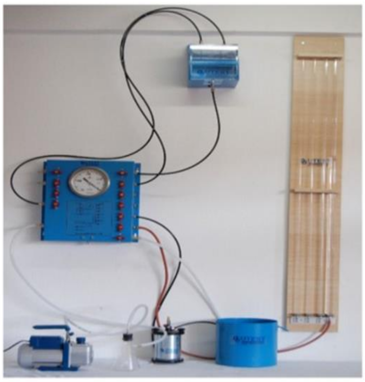


Figure 2: Particle size curves of samples

Falling Head permeability test

The falling head permeability test is a common laboratory testing method used to determine the permeability of fine-grained soils with intermediate and low permeability such as silts and clays. This testing method can be applied to an undisturbed sample [16]. the set of equipment is composed of a standpipe and manometer tube with graduated scale, Cell body, Filter paper,



Stopwatch, Vanier caliper, vaccum pompe and water reservoir (figure 3).

Figure 3: Falling head permeability set

The falling head permeability test involves flow of water through a relatively short soil/rock sample connected to a standpipe which provides the water head and also measuring the volume of water passing through the sample. Before starting the flow measurements, undisturbed sample can be taken by means of core cutter, ensure that the sample is tight fit in the body and there are no cavities around the perimeter through which water can pass; measure the mean internal diameter (D) and length (L); measure the diameter of the standpipe.

The soil sample is contained within a cylinder placed in a water bath to saturate, and the standpipes are filled with de-aired water to a given level. The test then starts by allowing water to flow through the sample until the water in the standpipe reaches a given lower limit. The time required for the water in the standpipe to drop from the upper to the lower level is recorded. Often, the standpipe is refilled, and the test is repeated for couple of times. The recorded time should be the same for each test within an allowable variation of about 10% otherwise the test is failed.

During the entire test, the water temperature was 24 °C. From the obtain data, we calculate the permeability (K) for each trials using the formula for falling head method:

$K = a*L/(A*\Delta t) *2.3*\log10 (H0/H1)$in which we have:

K: Coefficient of permeability (mm/s).L: the height of the sample column.

A: the sample cross section.

a: the cross section of the standpipe.

Δt: the recorded time for the water column to flow though the sample.

H0 and H1: the upper and lower water level in the standpipe measured using the same waterhead reference.

Constant pressure system (oil /water)

This apparatus provides an infinitely variable constant pressure using an adjustable spring type dead weight pressure feedback system connected in-line with a pump and an oil/water interchange vessel [17]. It was connected to devices to form a system that allows pumping water and carbon dioxide gas namely Constant pressure (oil/water) system for pressure up to 3500 kpa, Automatic command and control console SERCOMP 7, CO2 storage bottle, Sample cell, Measuring tubes, Manometers and Manifold.

We have connected the CO2 bottle to one of the inputs of the manifold, while the output is connected to the inlet of the cell containing the oil-saturated core sample with outlet connected tothe measuring tubes filled with water. The automatic pressure control console is connected toone side of the cell to keep the hydrostatic pressure inside the cell stable. Pressure gauge wasinstalled to monitor the cell pressure (figure 4).

We have selected 2 core samples (the highest and the lowest relative permeability), and each one is saturated with an oil of 0.84 kg per liter density to approximate the density of Hassi Messaoud light oil. As of the process of pumping water and carbon dioxide, it was done through a plug with a 59.4 mm diameter hole in the middle through which we passed the pumping pipe.

Water and CO2 injection

We applied different pressures at different time intervals so that constant pressure system (oil/water) exerts pressure on the artificial core sample by pumping water to sweep all the oil drops. The purpose of this is to recover the residual oil trapped in the pore walls.

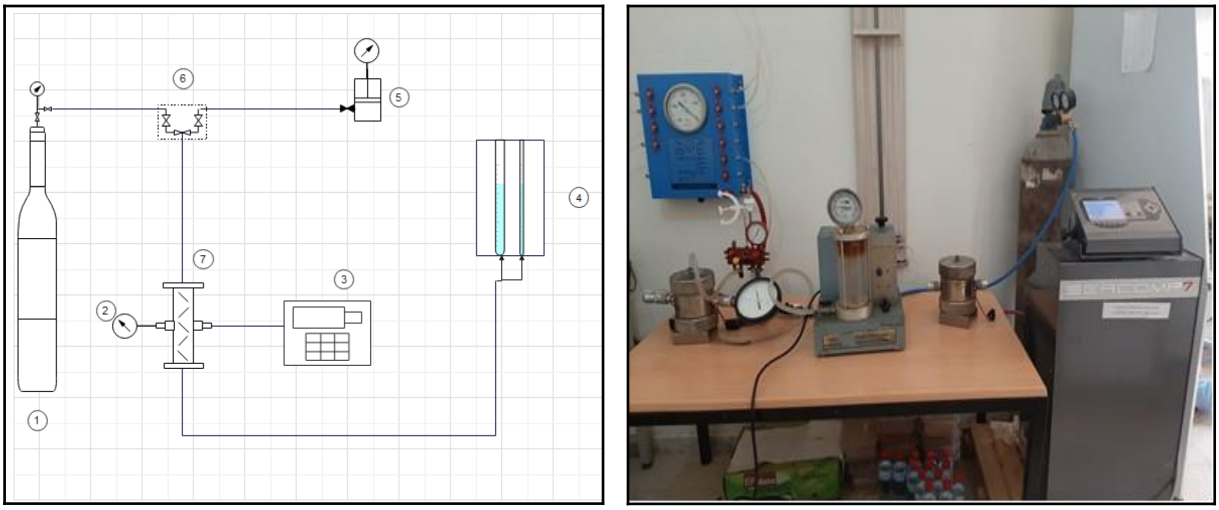


Figure 4: (a) Schematic diagram and (b) photo of the constant pressure system experimentalapparatus. (1) storage bottle, (2) manometer, (3) Automatic command and control console Sercomp 7, (4) Measuring tubes, (5) constant pressure system(oil/water), (6) manifold, (7) Sample cell.

After this phase and instead of water, we pumped CO2 gas at different pressures for different time intervals. The process is continued and we monitor the water level in the measuring tubes to assess the flow of residual oil.

To control the fluids flow, four manometers are installed: the first one in the carbon dioxide bottle, the second in the manifold (distributor), the third in the cell wall of the sample and the fourth one is installed in the command and automatic control console.

The experiment was performed by increasing the pressure each time to monitor the oil yield increase. The water level measurement process was carried out through 2 measuring tubes of two different diameters. We applied grease on all inlets and outlets to prevent leakage.

To simulate the temperature effect on the carbon dioxide pumping process, we heated both samples in an oven below 80 °C prior to oil extraction with carbon dioxide.

Results and discussions

Results of the permeability estimated by Kozney formula

In order to estimate the permeability by the results of the formula of Kozney, we grouped 5 granulometric curves corresponding to soils whose permeability was measured by Falling head permeability set (table 1).

Table1: Results of permeability by formula Kozney

	D10	D30	D50	D70	D90	KG 0.25	KG 2.8
S1	0.00045	0.0658	0.1562	0.2962	0.4309	1.2351E-06	1.3833E-05
S2	0.00045	0.0242	0.0465	0.1283	0.3651	1.186E-06	1.3283E-05
S3	0.00045	0.0797	0.2604	0.3563	0.4521	1.2416E-06	1.3906E-05
S4	0.0476	0.151	0.2493	0.3496	0.4499	0.00463393	0.05190006
S5	0.000458	0.000901	0.00703	0.0472	0.3407	5.2217E-07	5.8483E-06

Results and discussion of the Falling Head Permeability Set

The relative permeability coefficient is determined by the flow rate, as we note in Table (2), that we conducted the experiment at four different times to obtain the average relative permeability for each sample.

Table 2: Results and discussion of the falling head permeability test

Samples	Time(sec)	Waterlevel		Permeability mm/sec	Volume
		H0(mm)	H1(mm)	K	v(ml)
S-1	600	1450	220	0.002169	550
	1200	220	180	0.000115	570
	1800	180	170	2.19E-05	590
	2400	170	167	5.12E-06	600
Average				0.000578	577.5
S-2	600	1450	855	0.000608	250
	1200	855	750	7.54E-05	280
	1800	750	700	2.65E-05	300

	2400	700	660	1.69E-05	330
Average				0.000182	290
S-3	600	1450	1010	0.000416	100
	1200	1010	925	5.06E-05	110
	1800	925	780	6.54E-05	180
	2400	780	650	5.24E-05	260
Average				0.000146	162.5
S-4	600	1450	1410	3.22E-05	1
	1200	1410	1400	4.09E-06	1.5
	1800	1400	1398	5.48E-07	1.55
	2400	1398	1397	2.06E-07	1.6
Average				9.26E-06	1.4125
S-5	600	1450	1041	0.000381	3
	1200	1041	1040	5.53E-07	3.1
	1800	1040	1039	3.69E-07	3.11
	2400	1039	1038	2.77E-07	3.12
Average				9.56E-05	3.0825

Table 2: Results and discussion of the falling head permeability test

Over time (t), once inlet valves are closed, water will start to drop immediately in the manometer tube from H0 to H1, and enters the core sample and measuring the volume (V) of water passing through the last one.

Then we calculated the relative permeability of each sample with the aforementioned relationship, and after analyzing these results shown in Figure (5):

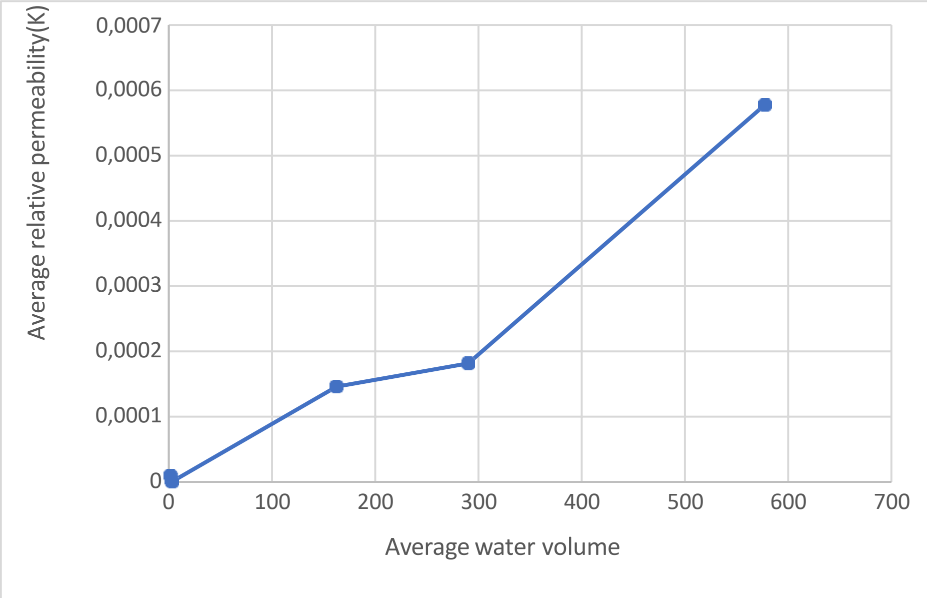


Figure 5: Relative mean-permeability curve in terms of average size

We concluded that these low soil permeability rates are due to its classification: for clay, it is mainly composed of very fine particles and very poor permeability, and holds more moisture than sandy soils, but is highly compressible.

As a result, we can describe the permeability coefficient of the Hassi Messaoud reservoir, as weak and clarify that there is a linear relationship between permeability and porosity for each sample that is defined as the ratio of the effective permeability of a particular liquid at a certain saturation to the absolute permeability of that liquid at total saturation. Calculating relative permeability allows comparison of the different abilities of liquids to flow in the presence of each other, because the presence of more than one liquid generally prevents the flow. It is

assumed that the higher the porosity, the higher the permeability (the higher the hydraulic conductivity coefficient), and according to other studies, the permeability is also affected by the shape and arrangement of the pores or the amount of slurry, so if the latter is not interconnected, the fluids inside the sample will remain confined (isolated) and can not leak [18].

Water injection (Sample 1 and 5):

The first stage of the experiment depends on injecting water into the first and fifth core samples selected from the largest and smallest permeability with increasing pressure in conjunction with time to extract the saturated oil and finding a path through which the remaining oil moves in the base samples with the aim of leaving only the remaining oil to be extracted by carbon dioxide injection. Through the results, we noticed that the higher the pressure of the water that is pumpedin conjunction with time, the more there is an exit of oil through the measuring tubes, and this increase is illustrated as shown in the Table 3.

Table3: Water injection results

	T	P	H
S-1 Water injection	0-10	5	20
	10-20	10	25
	20-30	20	26
	30-40	25	26
	40-50	30	26
	50-60	35	26
	60-70	5	28
S-5 Waterinjection	0-10	5	20.3
	10-20	10	20.2
	20-30	20	20.6
	30-40	25	20.6
	40-50	30	20.6
	50-60	35	20.6

P: pressure (bar); T: time (min); H: water level (cm)

The level of oil recovery at increasing pumping pressures every period of time for the two core samples under a temperature of 70 ° C and a pressure of 10 bar applied to the cell walls. Through the first stages of water injection under pressure of 5 and 10 bar, the water level was increasing, through the exit of the oil to reach 22 cm and 25 cm for the first sample and 20.44 cm for the second, then stabilized after this increase in the rest of the pressures to reach 26 cm and 20.6 for the two samples respectively, let's say that the water in the first stage of pumping at a pressure of5 and 10 bar was penetrating into the pores and pushing the oil out, but when the water pumping pressure increased and became greater than 10 bar, which is the pressure applied to the cellwalls, the water began to accumulate and the oil is saturated with it.

So that the results appeared in the form of slight increases and then stabilized, which is probably due to the decrease in the absolute permeability of the two core samples. For this reason, we have fixed the pumping pressure at 5 bar, the most appropriate option for overflowing withwater, to return the increase in extraction again, and the experiment lasted about 15 hours to extract the large proportion of the oil.

CO2 injection results

From last study results, we chose 2 different relative permeability samples (1 and 5) and applied on them carbon dioxide pumping process with constant pressure to identify the capability of extracting residual oil from different relative permeability. And the results were as follows:

Table 4 shows the results of the carbon dioxide (CO2) pumping experiment in the first and fifth samples, with average relative permeability (5.77E-04, 9.56E-05) respectively. We note that the higher the carbon dioxide pumping pressure, the higher the level of water mixed with the remaining extracted oil. We continued to increase the pressure to 28 bar maximum pumping pressure for two hours, and the liquid level in the measuring tubes did not change.

Table 4: CO2 gas injection

	P	6			10			15			20			25			28		
	T	0-10	10-20	20-30	0-10	10-20	20-30	0-10	10-20	20-30	0-10	10-20	20-30	0-10	10-20	20-30	0-10	10-20	20-30
S-1	H	22.6	22.7	22.8	23	23.2	23.2	23.3	23.4	23.5	23.5	23.6	23.6	23.7	23.7	23.8	23.8	23.8	23.8
S-5		20.2	20.2	20.4	20.5	20.5	20.6	20.6	20.7	20.8	20.8	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9

P: pressure (bar); T: time (min); H: water level (cm)

The results show that the temperature rises from 27C° to 71C° (at a pressure of 27.6 bar) causes the dissolution of carbon dioxide in the oil by approximately half. At a temperature of 70C° and 28 bar for our study, and with the increase in temperature, the density of carbon dioxide gas decreased, which necessitates the presence of more high pressure to reach the state of mixing [19, 20].

And through these results, we estimated that 20 bar is the appropriate pressure for the process of pumping carbon dioxide into the samples at a temperature of 70C°, so that the process lasted from 48 to 50 hours, which led to a complete halt to the exit of the remaining oil, with an estimated volume of 10 ml and 6 ml in order, after separating it from the water (Figure 6).

The injection of miscible carbon dioxide increases the effectiveness of microscopic displacement by reducing or eliminating the surface tension between oil and carbon dioxide. And through our experience, we used this technique after flooding with water, as it works to find a path through which the remaining oil moves, which results in a decrease in the residual oil saturation, but the gas is generally less viscous and less dense than oil, which may reduce the effectiveness of displacement, and thus remains saturated with oil the remainder is relatively high. But it does not apply to all cases. Rare cases were recorded in which the saturation of the remaining oildecreased to 2%.

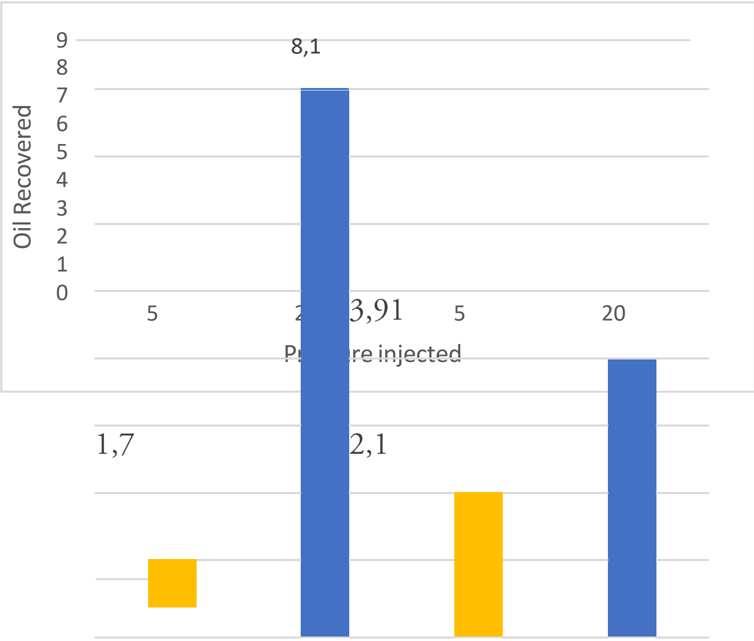


Figure 4: Chart of oil recovered vs injection pressure

After this experiment, and to verify that we had extracted almost all the residual oil in the core samples, we monitored the time and this was done by closing the carbon dioxide gas bottle for 10 minutes to check whether there was a pressure drop or not (if the pressure decreased through the manometer, the pores are empty, but if the pressure remained stable the matrix still full, so we will continue to pump carbon dioxide), but for the study that we carried out, it was found after supervision time that the pressure decreased and its interpretation that the residual oil was completely extracted.

As for the second verification, at the end of the experiment we cut the sealing pressure of the cell walls which was set at 10 bar to ensure that the pressure applied to the walls was effective when the pressure gauge dropped.

Conclusion:

The mechanism of enhanced oil recovery using carbon dioxide has been studied for the Hassi Messaoud basin by making samples that simulate the facies of this reservoir (Clayey Sandstone of Triassic). The relative permeability of each sample was measured with water. The carbon dioxide gas was also injected in the samples to assess the extent of its effect on extracting the residual oil and to estimate its extracted volume. This study allowed us to draw the following conclusions:

Extent of the effect of pressure and temperature on the process of enhanced oil recovery with carbon dioxide gas. The process of pumping water as an outflow mechanism before the process of pumping carbon dioxide, it was successful to reduce the Sroil under the pumping pressure of 5 bar and a temperature of 70 ° C suitable for letting the water push the oil out.

The process of extracting oil enhanced with carbon dioxide, which was carried out with a constant pressure system, the results of which proved the extraction of approximately 10 ml of the residual oil under pressure of 20 bar and 70 degrees Celsius, With these conditions, we can say that the miscible carbon dioxide flood is able to extract the oil by reducing the interfatial tension (IFT) due to the mass transfer between the displacement and displacement phases during the evaporative / condensation gas drive, oil swelling, and lowering the oil viscosity, which leads to re-pressurization of the tank and relieve capillary forces. Instead, we estimate in the future the rate of oil production in the Hassi Messaoud reservoir with enhanced oil recovery (EOR) with CO2 about 35 % of the residual oil.

References:

[1] Camporeale, C., Del Ciello, R., & Jorizzo, M. (2021). Beyond the Hydrocarbon Economy: The Case of Algeria. *Sustainable Energy Investment: Technical, Market and Policy Innovationsto Address Risk*, *165*.

[2] Rey, S., & Hazem, S. (2020). Labor Productivity and Economic Growth in a Hydrocarbon-Dependent Economy: The Algerian Case, 1984–2015. *The European Journal of Development Research*, *32*, 587-611.

[3] Xiangguo, L. U., Bao, C. A. O., Kun, X. I. E., Weijia, C. A. O., Yigang, L. I. U., Zhang, Y., & Zhang, J. (2021). Enhanced oil recovery mechanisms of polymer flooding in a heterogeneousoil reservoir. *Petroleum Exploration and Development*, *48*(1), 169-178.

[4] Burrows, L. C., Haeri, F., Cvetic, P., Sanguinito, S., Shi, F., Tapriyal, D., ... & Enick, R. M. (2020). A literature review of CO2, natural gas, and water-based fluids for enhanced oil recoveryin unconventional reservoirs. *Energy & Fuels*, *34*(5), 5331-5380.

[5] Haghighi, O. M., Zargar, G., Khaksar Manshad, A., Ali, M., Takassi, M. A., Ali, J. A., & Keshavarz, A. (2020). Effect of environment-friendly non-ionic surfactant on interfacial tension reduction and wettability alteration; implications for enhanced oil recovery. *Energies*, *13*(15), 3988.

[6] Deng, X., Tariq, Z., Murtaza, M., Patil, S., Mahmoud, M., & Kamal, M. S. (2021). Relative contribution of wettability Alteration and interfacial tension reduction in EOR: A critical review.*Journal of Molecular Liquids*, *325*, 115175.

[7] H. Hawez and Z. Ahmed, "Enhanced oil recovery by CO2 injection in carbonate reservoirs," *WIT Transactions on Ecology and the Environment*, vol. 186, no. December 2014, pp. 547–558,2014, doi: 10.2495/ESUS140481.

[8] Yu, H., Fu, W., Zhang, Y., Lu, X., Cheng, S., Xie, Q., ... & Lu, J. (2021). Experimental study on EOR performance of CO2-based flooding methods on tight oil. *Fuel*, *290*, 119988.

[9] Kumar, N., Sampaio, M. A., Ojha, K., Hoteit, H., & Mandal, A. (2022). Fundamental aspects, mechanisms and emerging possibilities of CO2 miscible flooding in enhanced oil recovery: A review. *Fuel*, *330*, 125633.

[10] Baouche, R., Sen, S., Debiane, K., & Ganguli, S. S. (2020). Integrated reservoir characterization of the Paleozoic and Mesozoic sandstones of the El Ouar field, Algeria. *Journalof Petroleum Science and Engineering*, *194*, 107551.

[11] Zeddouri, A., Hadj-Saïd, S., & Laouini, H. (2011). Etude de la fracturation des réservoirs cambriens du champ d'El Gassi, Sud-Est algérien. *Journal of hydrocarbons mines and environmental research*, *2*(2).

[12] Ameur Zaimeche, O., Zeddouri, A., Kouadria, T., Kechiched, R., & Belksier, M. S. (2014, March). Use of Cluster Analysis method in log's data processing: prediction and rebuilding of lithologic facies. In International Conference on Environmental Science and Geoscience (ESG'14) Venice, Italy (pp. 98-101).

[13] Yu, F. (2021). Particle breakage in granular soils: a review. Particulate Science and Technology, 39(1), 91-100.

[14] Ye, Y., Xu, Z., Zhu, G., & Cao, C. (2022). A modification of the Kozeny–Carman equation based on soil particle size distribution. Arabian Journal of Geosciences, 15(11), 1079.

[15] V. Savatier. (1999). Perméabilité estimée par la granulométrie. Proposition d'une méthode ettest de son efficacité." Revue Française de Géotechnique, 87, 63-69

[16] Sun, Y., Causse, P., Benmokrane, B., & Trochu, F. (2020). Permeability measurement of granular porous materials by a modified falling-head method. Journal of Engineering Mechanics,146(9), 04020101.

[17] Lovick, J., & Angeli, P. (2004). Experimental studies on the dual continuous flow pattern inoil–water flows. International journal of multiphase flow, 30(2), 139-157.

[18] Wang, M., Yang, Z., Shui, C., Yu, Z., Wang, Z., & Cheng, Y. (2019). Diagenesis and its influence on reservoir quality and oil-water relative permeability: A case study in the Yanchang Formation Chang 8 tight sandstone oil reservoir, Ordos Basin, China. Open Geosciences, 11(1),37-47.

[19] Allal, M. A., Brancolini, A., Smail, F., Kaaroud, Z., Kriat, M. A., & Elmutardi, M. (2023). Miscible Water Alternating Gas Injection WAG Field Scale Application in Algeria: An Effective Way to Improve Oil Recovery, Rejuvenate Mature Field and Develop Opportunities to Stream Gas Sales. *Society of Petroleum Engineers - ADIPEC, ADIP 2023*. https://doi.org/10.2118/216168-MS

[20] Lebouachera, S. E. I., Chemini, R., Khodja, M., Grassl, B., Tassalit, D., & Drouiche, N. (2018). Experimental investigations of SDS adsorption on the Algerian rock reservoir: chemical enhanced oil recovery case. *Research on Chemical Intermediates*, *44*(12), 7665–7690. https://doi.org/10.1007/S11164-018-3580-0