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Experimental Investigation of Enhanced Recovery in Unconventional Liquid Reservoirs using CO_2: A Look Ahead to the Future of Unconventional EOR

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Abstract

The poor rock quality and matrix permeability several orders of magnitude lower than conventional oil reservoirs observed in unconventional liquid reservoirs (ULR) presents many uncertainties on the storage capacity of the rock and the possibility of enhancing recovery. The technological advances in multiple stage hydraulic fracturing and horizontal drilling have improved the overall profitability of oil shale plays by enhancing the matrix – wellbore connectivity. The combination of these technologies has become the key factor for the operators to reach economically attractive production rates in the exploitation of ULR, causing a lot of focus on their improvement. However, as the reservoir matures, primary production mechanisms no longer drive oil to the hydraulic fractures, making the improvement of matrix – wellbore connectivity insufficient to provide economically attractive production rates. Therefore, the need to develop enhanced recovery techniques in order to improve the displacement of the oil from the matrix, maintain profitable production rates, extend the life of the assets and increase ultimate oil recovery becomes evident.

This study presents experimental results on the use of CO_2 as an enhanced oil recovery (EOR) agent in preserved, rotary sidewall reservoir core samples with negligible permeability. To simulate the presence of hydraulic fractures, the ULR cores were surrounded by high permeability glass beads and packed in a core holder. The high permeability media was then saturated with CO_2 at constant pressure and temperature during the experiment. Production was monitored and the experiment was imaged using x-ray computed tomography to track saturation changes inside the core samples.

The results of this investigation support CO_2 as a promising EOR agent for ULR. Oil recovery was estimated to be between 18 to 55% of OOIP. We provide a detailed description of the experimental set up and procedures. The analysis of the x-ray computed tomography images revealed saturation changes within the ULR core as a result of CO_2 injection. A discussion about the mechanisms is presented, including diffusion and reduction in capillary forces. This paper opens a door to the investigation of CO_2 enhanced oil recovery in ULR.

Introduction

There is a lot of uncertainty regarding volumes in place and production forecast when it comes to unconventional liquid reservoirs. It is estimated that these tight oil reservoirs contain several hundred billion barrels in known basins in the United States. These accumulations were discovered several decades ago, but their exploitation was not economic due very low matrix permeability, often in the order of micro and nanodarcy. Recent technological advances that first enabled the exploitation of tight gas shale plays were successfully implemented in tight oil reservoirs the last decade. Economic exploitation was achieved and the oil industry and academia rapidly focused on these challenging resources development, optimizing drilling and hydraulic fracturing design and execution techniques. As a result, US oil production increased from 5 million STB/D in 2005 to 6.5 million STB/D in 2012 reversing a decline trend that started in 1986 (EIA, 2013).

The use of hydraulic fracturing allows the well to connect with a larger volume of reservoir matrix and in some cases with naturally occurring fractures and micro fractures. When multiple stage hydraulic fracturing is performed in horizontal wells, the stimulated reservoir volume is greatly increased leading to economic oil production rates even from rocks of very low matrix permeability. For most ULR production declines rapidly and stabilizes at a low rate, the estimates of oil recovery during primary production are low, ranging from 5 to 10% of OOIP (Hoffman, 2012). Even though the combination of horizontal drilling and hydraulic fracturing gives economic oil rates, it does nothing to improve displacement efficiency and reduce residual oil saturation. High capillary forces related to small pore and pore throat size causes the majority of the oil to remain trapped in the low permeability rock matrix. This situation makes the application of enhanced oil recovery a necessary step to efficiently exploit unconventional liquid reservoirs.

Carbon dioxide is a powerful agent for enhanced oil recovery. It reaches miscibility at lower reservoir pressure compared to nitrogen and hydrocarbon gases, swells the oil, reduces its viscosity and reaches supercritical state at the pressure and temperature of most oil reservoirs resulting in oil like density that reduces override effects. By 2012 CO_2 miscible flooding accounted for 308,564 STB/D of oil, 41% of the total US EOR daily production, which is more than any other EOR method. CO_2 immiscible flooding added another 43,657 STB/D (Anonymous, 2012). Moreover, CO_2 has been reported to be successful during field applications under unfavorable conditions like heavy oil and oil wet naturally fractured reservoirs, where water flooding is largely unsuccessful (Beliveau, 1987, Sahin et al., 2008, Sahin et al., 2012). CO_2 injection has been also considered for unconventional liquid reservoirs. Hoffman (2012) used numerical simulation to study gas injection through horizontal wells with longitudinal hydraulic fractures in the Bakken shale. Porosity was 6 – 8%, permeability 2.5 md and oil was 42ºAPI. Miscible CO_2 injection increased recovery from 6.02% obtained under primary production to 21.58% of OOIP. Vega et al. (2010) studied miscible CO_2 injection into siliceous shale with 1.3 md permeability and 34% porosity. Experimental and simulation results together with computed tomography image analysis revealed CO_2 was able to penetrate from the fracture to the matrix and recover almost all the oil. Mohanty et al. (2013) studied miscible CO_2 huff and puff in a shale matrix typical of the Bakken formation. A compositional simulator was used to represent multiple vertical fractures along a horizontal well in a formation with matrix permeability and porosity of 0.01 md and 8% respectively. CO_2 injection was found to outperform primary production for the case of a heterogeneous reservoir.

The purpose of this investigation is to evaluate CO_2 EOR in ULR with lower permeability than reported before. We used preserved sidewall shale cores saturated with oil and with permeability in the nanodarcy range, preventing us from performing CO_2 flooding as conventionally conceived because it could not be directly injected into the matrix. We developed a technique to pack the sidewall core samples into the core holder using glass beads to simulate the presence of a hydraulic fracture. With this approach we did not have to cut the cores and we did not alter the rock properties and the original fluid saturation. The core was soaked in CO_2 for several days and production was allowed in intervals. Changes in saturations were tracked using x-ray computed tomography (CT). The analysis of the images revealed that CO_2 was able to penetrate the cores, resulting in an oil recovery estimated in the range of 18 to 55% of OOIP. We will present a discussion of our results on the basis of viscous displacement, diffusion and solubilization mechanisms. Additionally, we draw a research path using numerical simulation and laboratory experiments to evaluate the potential of these mechanisms aiming to determine if they can support an economic continuous CO_2 injection process in reservoirs where conventional flooding cannot be performed due to adverse rock properties, and compare that scenario in the basis of recovery and economics with a “huff and puff” CO_2 injection.

Description of Equipment and Procedures

Two experiments were conducted in this investigation. The temperature was 150 ºF for both experiments. The pressure was 3000 psi in the first experiment and 1600 psi in the second. Two preserved sidewall shale cores saturated with oil were used in each experiment. The petrophysical properties of the rock are unknown, but their permeability is so low that CO_2 injection through the matrix was not possible. Therefore, conventional procedures to clean, measure pore volume and re-saturate the cores with produced oil were dismissed. That situation prevents us from presenting balances of injected and produced fluids and properly account for recovery. TABLE 1 presents the conditions of the experiments and the dimensions of the cores used.

Fig. 1 - Preserved sidewall cores 1 and 2 after 1st Experiment.

TABLE 1– EXPERIMENTAL CONDITIONS AND CORE DIMENSIONS				
	1st Experiment		2nd Experiment	
Temperature, ºF	150		150	
Pressure, psi	3000		1600	
Core number	1	2	3	4
Core diameter, cm	2.53	2.53	2.53	2.52
Core length, cm	3.97	3.48	3.62	3.29
Core bulk volume, cm^3	19.94	17.50	18.20	16.42

We simulated the presence of a hydraulic fracture by surrounding the cores with a high permeability media created from glass beads. This approach was selected for several reasons. The high permeability media ensured that pure CO_2 at high pressure was in contact with the shale rock at all times, which almost eliminated compositional effects as the CO_2 volume in the fracture was several orders of magnitude higher than the pore volume of the core samples. We chose this approach over cutting the core in half to avoid altering the core during the cutting process. The cutting element alters the rock properties by polishing its surface and reducing permeability. Also, the fluid used during the cutting process can imbibe into the matrix causing important alterations due to the small pore volume. The approach selected in this investigation correctly represents the physics of a hydraulic fracture.

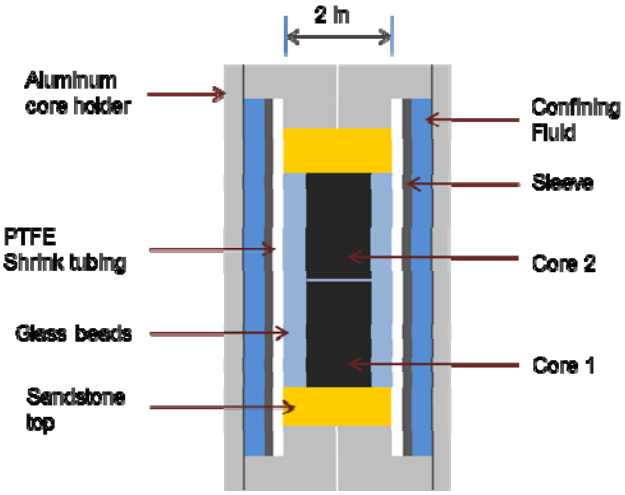

Fig. 2 - Core assembly schematic. The core was placed horizontally in the displacement equipment.

Two clean Berea sandstone samples acted as filters at either end of the setup to prevent the glass beads from entering the production tubing. Polytetrafluoroethylene (PTFE) shrink tubing confined the outside of the core setup. Fig. 2 shows a schematic of the setup. The core assembly was mounted in a Hassler type core holder. The core holder was placed in a water bath which was heated to reservoir temperature; an even temperature was kept by circulating heated water continuously.

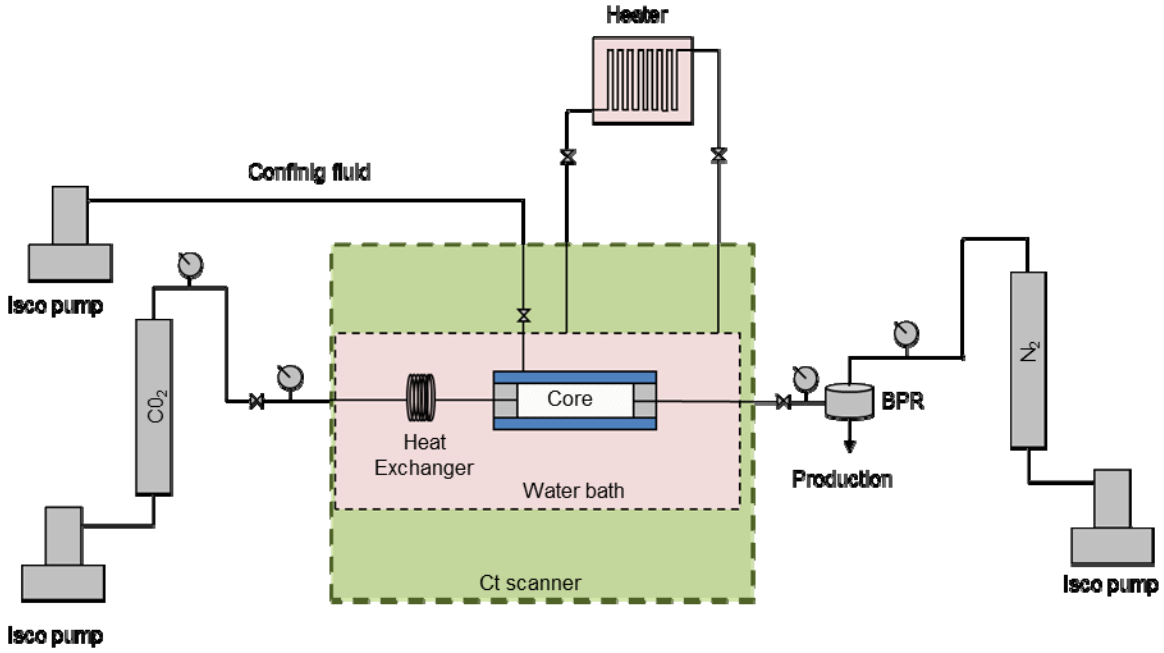

Fig. 3 - Schematic of the displacement equipment

The whole assembly was mounted inside a medical CT-scanner to monitor changes in density. Distilled water was used as confinement fluid and the pressure was kept 250 psi above the reservoir pressure. A dome loaded back pressure regulator kept the reservoir pressure at 3000 psi in the first experiment and 1600 psi during the second experiment. The system was pressurized to 100 psi below the back pressure with CO_2 which was injected through an accumulator. When we reached the desired pressure and temperature the system was isolated. Twice a day, the pressure in the system was increased to above the back pressure, resulting in production of carbon dioxide and any oil from the core samples. After about one hour of production the pressure was again stabilized to just below the back pressure, meaning that production was allowed in stages. We chose this approach because of the high volume of CO_2 compared to the pore volume of the core samples. The CO_2 saturation in the high permeability media is therefore assumed to be close to 1 throughout the experiments. CT-scans were taken at about 6 hour intervals to observe any changes in the density of the system. Fig. 3 shows a schematic representation of the displacement equipment.

Presentation and Discussion of Results

Oil recovery and core mass increment

In each of the experiments approximately 0.4 cm^3 of oil was recovered (Fig. 4). As previously explained, porosity of the cores is unknown and therefore original oil in place (OOIP) and recovery factor (RF) cannot be calculated. To estimate the performance of carbon dioxide for EOR in these cores we set up a number of scenarios. Porosity was given a range from 0.3 to 0.6% based on published data from the field the cores were taken from. We did not find evidence of water saturation during the course of our experiments since no water production was observed. However, we do not discard the presence of water in the core since the mechanism responsible of the oil production in our experiments is not suitable for water production. Therefore, we considered a range for initial water saturation from 0 to 30%.

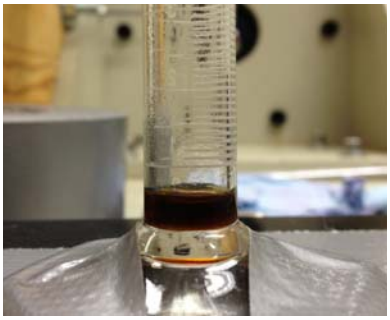

Fig. 4 - Crude oil recovered during the first experiment. The oil looks lighter than produced oil in the field

TABLE 2 presents the four scenarios for oil recovery calculations. Recovery factor was high, ranging from 18 to 51% for the first experiment and from 19 to 55% for the second experiment. Oil produced from the field in question has dark color and API gravity of 36 °. The oil recovered during both of our experiments has a lighter color and seem to have low viscosity, suggesting vaporization of the hydrocarbons into the CO_2 as a recovery mechanism. The low volume recovered prevented us from measuring API gravity, viscosity or oil composition.

TABLE 2 – SCENARIOS FOR OIL RECOVERY

	1st Experiment				2nd Experiment			
Porosity, %	0.6	0.6	0.3	0.3	0.6	0.6	0.3	0.3
Water saturation, %	0	30	0	30	0	30	0	30
Recovery factor, %	18	25	36	51	19	28	39	55

The mass of the cores changed during the experiments. In the first experiment, core 1 increased its mass by 0.07 g (from 50.48 g to 50.55 g), while core 2 increased its mass by 0.06 g (from 45.39 g to 45.45 g). We were expecting a decrease in mass as a result of the production of crude oil. We attribute this unexpected result to the adsorption of carbon dioxide on the organic matter contained in the cores. The shale organics are nano porous materials characterized by a large internal surface area that is able to adsorb a significant amount of gas. Experiments in the Barnett shale (Kang et al., 2010) have shown adsorption as the dominant mechanism during CO_2 storage in organic shale, since up to 97% of the up taken gas is stored in adsorbed state inside the organic pores. Adsorption capacity depends on conditions of reservoir pressure and temperature and in the organic content of the rock. Pore diffusion was found to be the mechanism of transport for the free – gas molecules occupying the pore space, and surface diffusion the mechanism for the transport of the adsorbed phase near the internal surfaces of the kerogen like material

We consider that liquid hydrocarbons are stored in the pore space of the sidewall cores used in our experiments. On the other hand, CO_2 is not only able to occupy that space, but also has access to a much larger space for storage in an adsorbed state. This space can be orders of magnitude larger than the available pore space, leading to an increase in mass during the course of the experiment even when light oil components are being produced. To further support this theory, the mass of the core was tracked over time after the experiment was ended. 410 days later, the mass of core 1 decreased to 50.46 g and the mass of core 2 to 45.38 g. The decrement of the mass of both cores below their value before the experiments, indicates desorption of the CO_2 caused by a decrease of pressure and temperature to ambient conditions. Unfortunately, the second experiment was ended by a leak causing water to reach the core setup (cores 3 and 4). That situation prevented us from obtaining meaningful measurements of mass for this case.

CT number behavior

As detailed earlier during the description of the experimental procedure and equipment, the change in CT number was tracked over time during both experiments. The attenuation of X-ray intensity when passing through a material is a function of the density and composition of such material and it is expressed as CT number. For high energy scans density dominates over composition (Vinegar and Wellington, 1987).

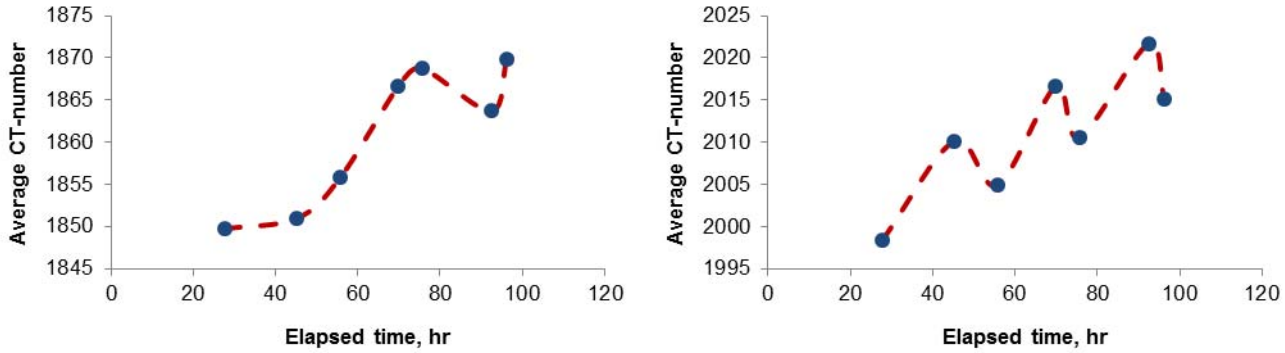

Fig. 5 - Average CT number a function of time for the 1st. Experiment. Core 1 to the left and core 2 to the right. Notice the increasing trend of CT number with time.

Fig. 5 shows the behavior of average CT number for cores 1 and 2 during the first experiment. Both cores showed an increase in CT number which can be correlated with increase in density. Since the composition of the reservoir oil or its density was not available, Fig. 6 shows the density of carbon dioxide together with the density of selected hydrocarbon components as a function of pressure at 150 ºF. The pressure of the first experiment is also indicated in the plot. At 3000 psi and 150 ºF, carbon dioxide has higher density than the hydrocarbon components which are likely main constituents of the crude oil, and the increase in CT number is an indication that CO_2 is able to penetrate the preserved sidewall core over time causing an overall increase in density.

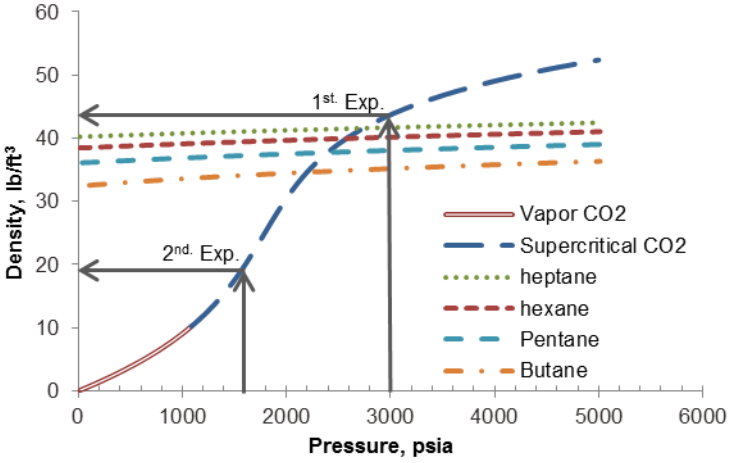

Fig. 6 - Density of carbon dioxide and some hydrocarbon components as a function of pressure at 150 ºF.

The decreasing trend of CT-number shown in Fig. 5 present fluctuations. We do not have a definite explanation for such behavior. One possible cause is the "huff and puff" like exploitation scheme we implemented in our experiments. As detailed earlier, the production end was kept closed, and was only opened in intervals to collect effluents. Consequently, when production was closed CO_2 solubilized in the oil leading to an increment in density and CT number. The opposite happened when production was open, since CO_2 and vaporized hydrocarbon components were allowed to move out of the core reducing density and CT number. Several cycles of this "huff and puff" like process were performed, possibly resulting in fluctuations in the behavior of CT number. We are planning experiments with a continuous injection of CO_2 that will help clarify this issue. Other causes we are considering are related to the equipment instead of the physical phenomena being observed, our next experiments will be performed using different equipment to further explore this possibility.

The analysis of the CT images also reveals that CO_2 is making changes in the cores over time (Fig. 7). A 6 color palette was used to high light where in the core samples the changes in CT-numbers took place. The heterogeneities of the core sample are visible and the color alterations are occurring along the bedding planes indicating that the penetration of CO_2 into the core is influenced by rock properties and fluid saturation patterns. The changes in CT-number demonstrated by the color scale presented to the right of Fig. 7 are increments in CT number, and therefore density, caused by the increasing presence of carbon dioxide inside the core.

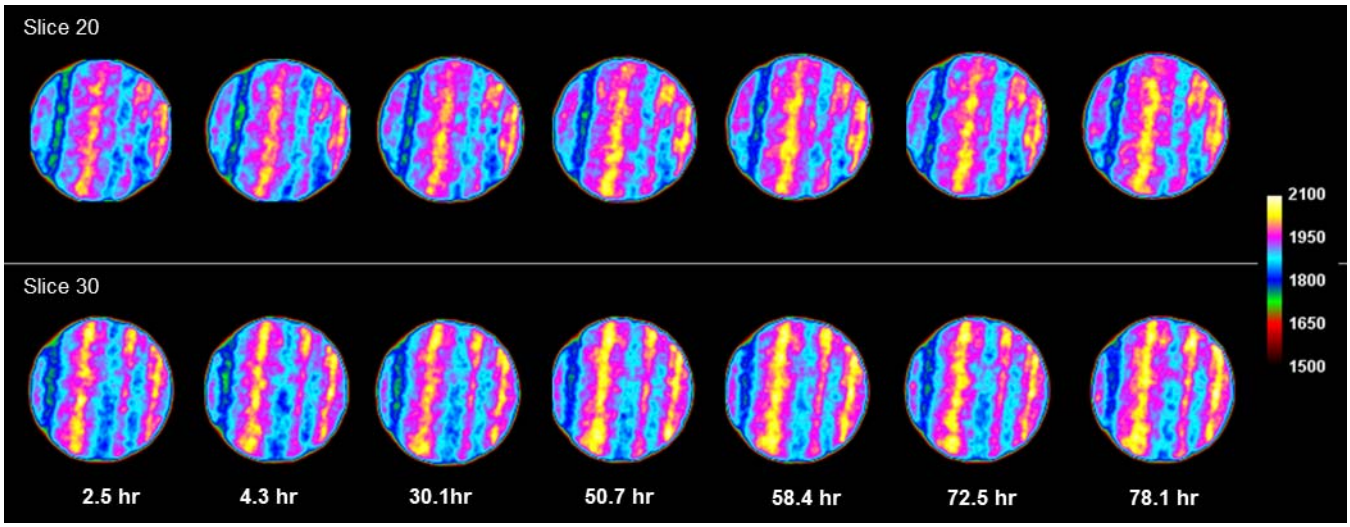

Fig. 7 - CT images for slices 20 and 30 of core 1 during the 1st Experiment. The images show the change in CT number as a function of time.

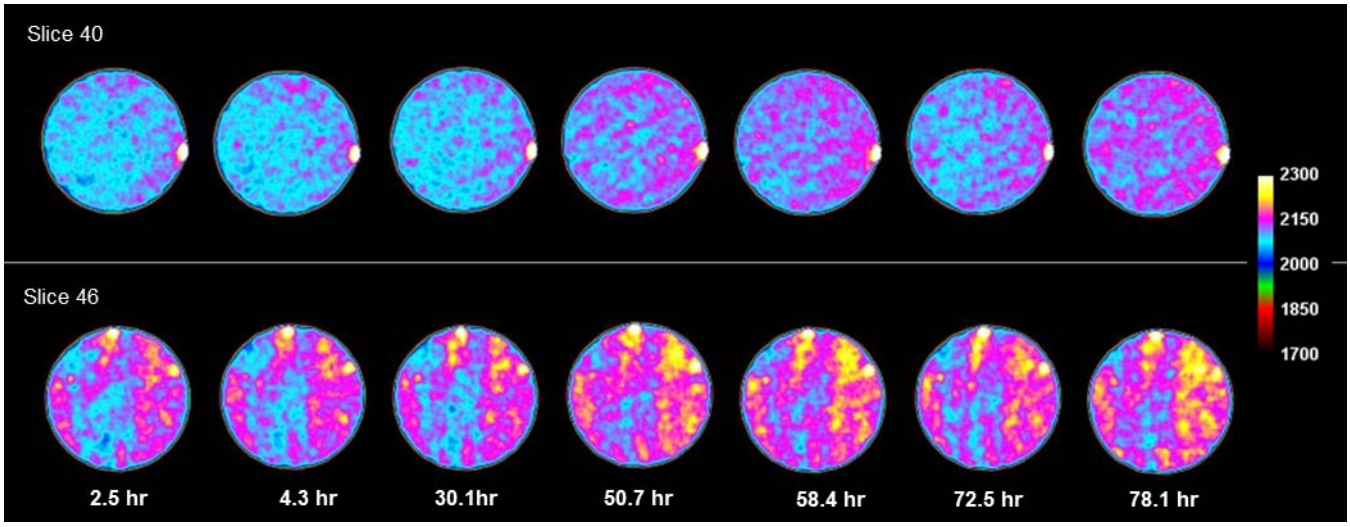

Fig. 8 - CT images for slices 40 and 46 of core 2 during the first experiment. The images show the change in CT number as a function of time

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The increment in CT number is small because it follows the change in density, and the density difference between the hydrocarbons and the carbon dioxide at 3000 psi is not large, as shown in Fig. 6. We believe that during the soaking process CO_2 dissolves into the oil, and the lighter hydrocarbon components are vaporized into the CO_2 as suggested by the appearance of the oil recovered and the CT images. The images do not show a displacement of one color by another, but a continuous change where one color seems to fade into the next. Additionally, the porosity in this rock is fairly low, possibly around 3 to 6%, making the overall density of the rock and fluid system mainly controlled by the rock density. That reduces the effect that slight changes in fluid density can have in the response of CT number. Simultaneously, CO_2 is being adsorbed on the surface of the organic matter present in the shale, which will result in an additional increase in CT number. The density of the shale matrix usually ranges from 150 to 175 lb/ft^3. A detailed assessment of the organic matter content of this sidewall cores and their adsorption capacity, surface diffusion and pore diffusion as transport mechanisms, and the role of the liquid hydrocarbon present in the pore space during that transport is required to better understand how the adsorbed CO_2 affects density and CT number.

Fig. 8 shows the CT images for core 2 used during the first experiment. This sidewall core is more homogeneous than core 1 and does not show bedding planes, but the increment in CT number is also evident as the images gradually change from sapphire blue to pink.

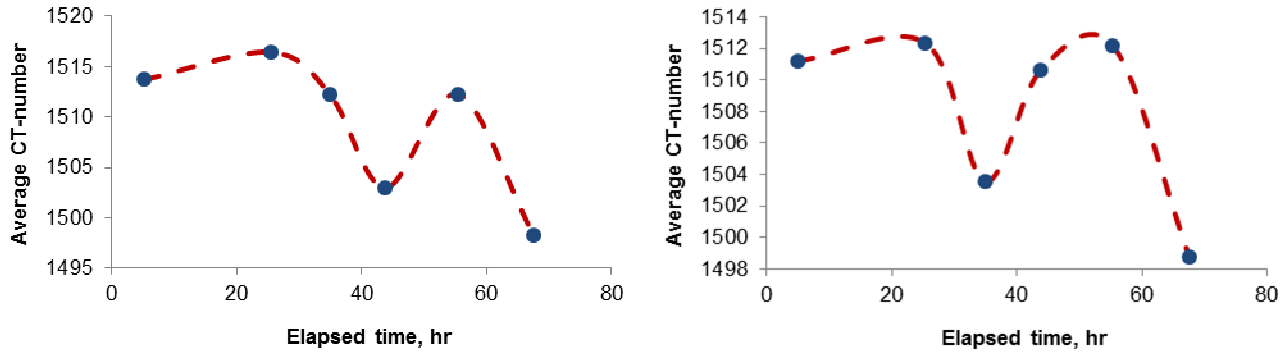

Fig. 9 - Average CT number as a function of time for the 2nd Experiment. Core 3 to the left and core 4 to the right.

To confirm the results of the first experiment, a second experiment was performed. In the second experiment, we decided to increase the density difference between the CO_2 and the crude oil, with the crude oil being the densest fluid. That was accomplished by selecting 1600 psi as the reservoir pressure and keeping the same temperature (150 ºF), resulting in a density of CO_2 significantly lower than the previous experiment, and below the density of the selected group of hydrocarbons (Fig. 6). The change in density caused the CT number trend to be reversed compared to the first experiment and we now observe a decreasing behavior (Fig. 9 - Fig. 11), which suggest the dissolution of CO_2 into the oil is controlling the overall density of the system. Even when the density difference is larger in the second experiment compared to the first, the changes in CT number are still small. Both reasons commented earlier, small pore volume and adsorption of CO_2 on the organic matter are still valid in this case, and a third reason can be added. Reducing the pressure may have negatively affected the solubilization mechanism as pressure could be lower than minimum miscibility pressure (MMP) for the 2nd experiment. An analysis of the crude oil is not available, but given an API gravity for the oil of 36 °, is very likely than MMP is lower than 3000 psi for CO_2, and therefore the 1st experiment was performed under miscible conditions whereas the 2nd could potentially be under immiscible conditions. In this case the absorption of CO_2 in the organic matter will also tend to increase the CT-numbers, effectively cancelling out some the decrease caused by the difference in density between CO_2 and crude oil.

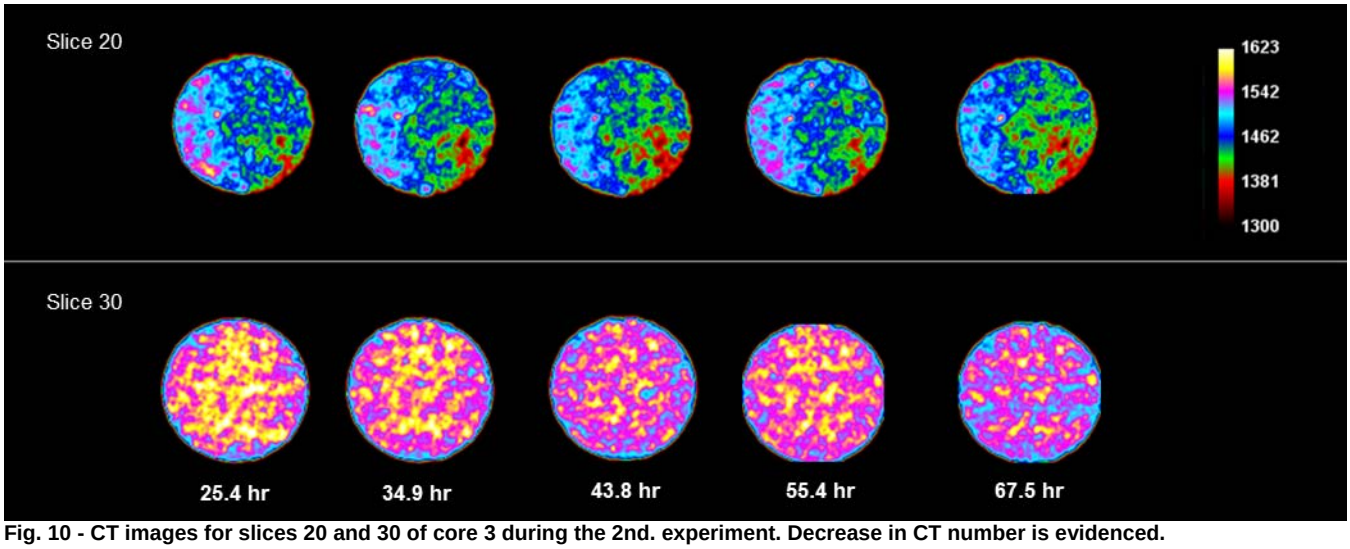

Fig. 10 - CT images for slices 20 and 30 of core 3 during the 2nd. experiment. Decrease in CT number is evidenced.

Even when both cores show a decreasing behavior, the behavior of CT-number as a function of time is not the same for core 3 and core 4 (Fig. 9). We believe this situation is caused by rock heterogeneities in physical properties and in organic content that affects solubilization, vaporization, diffusion and adsorption behavior resulting in different responses of CT-number, evidencing the complexity of the different phenomena present which are acting simultaneously.

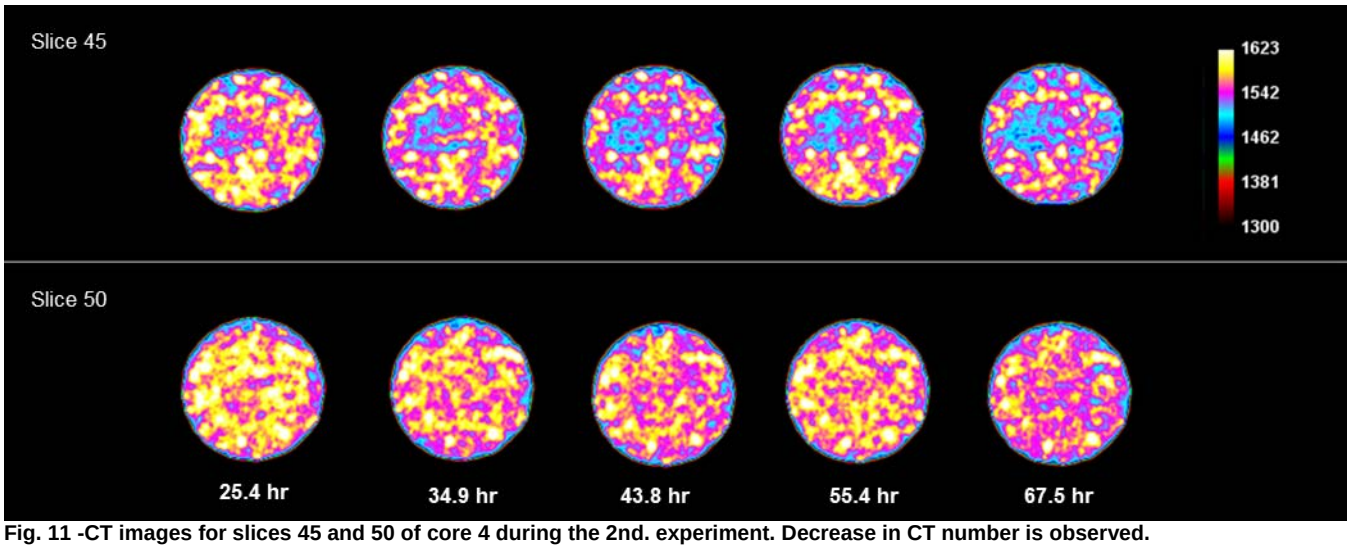

Fig. 11 -CT images for slices 45 and 50 of core 4 during the 2nd. experiment. Decrease in CT number is observed.

Future work

To further study the production and adsorption mechanisms we will modify our experimental procedure from a "huff and puff" like exploitation scheme to a continuous injection. This will enable the collection of oil recovery vs. time data to establish a time frame for the process that will help when setting up an economic scenario. Similar experiments will be performed using homogeneous sandstone cores for comparison and understanding the role of heterogeneity. Higher permeability rocks will be used to compare the behavior of CT number when CO_2 can easily access the pore volume. Dean Stark extraction will be used to clean the cores after the experiment to remove the remaining oil and estimate OOIP. Analysis of the rock samples and microscope photography will be used to establish organic content and pore size distribution. An attempt to match experimental results with numerical simulation will be done and a sensitivity analysis will be performed in the matched model to evaluate the contribution of the different mechanisms.

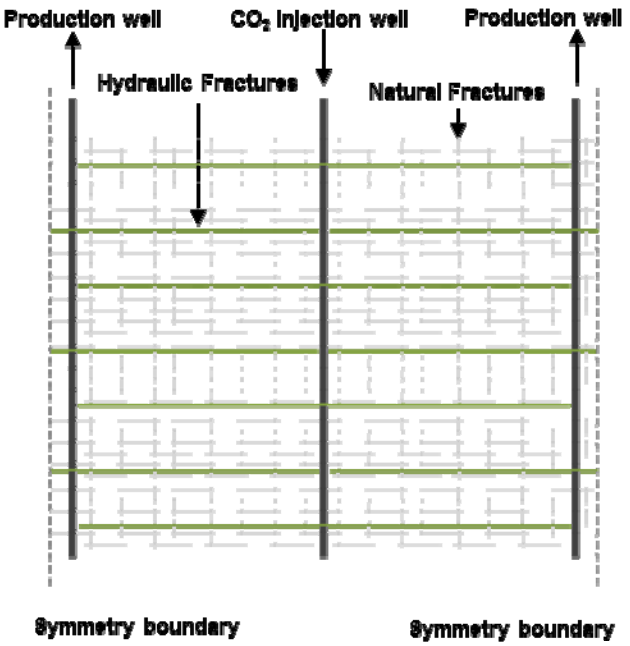

Fig. 12 - Schematic representation in map view of continuous injection exploitation scheme in ULR

Our ultimate goal is to set a numerical model based in our experimental data to evaluate the technical and economic feasibility to continuously inject carbon dioxide into a horizontal well hydraulically fractured in multiple stages, and produce through a couple of neighboring wells also hydraulically fractured in multiple stages (Fig. 12). The impact of the presence of a naturally occurring fracture network will be evaluated. Different conditions of pressure, temperature, fluid and rock properties will provide for a wider comprehension of the window for the application of the proposed exploitation scheme and its potential to enhance recovery in unconventional liquid reservoirs. This exploitation scheme will be compared with a "huff and puff" method in recovery enhancement potential and economics.

Conclusions

We have found evidence showing we can produce a significant percentage of OOIP by circulating carbon dioxide through a high permeability media that is connected to a matrix of low permeability (nanodarcy), where direct CO_2 injection is not possible. The high permeability media can be provided by a hydraulic fracture, a naturally occurring fracture network, or a combination of both.

The behavior of CT number and the characteristics of the produced oil suggest oil vaporization into the carbon dioxide as the main mechanism of oil production. After the oil has been vaporized, it can be easily transported outside the core holder.

The increase in mass of the preserved shale cores during the first experiment indicates they have a high capacity for the storage of carbon dioxide which is related to the organic matter content of the cores.

The behavior of CT number with time can be related to the density of the CO_2 injected, indicating that dissolution of CO_2 into the crude oil is controlling CT number behavior even with the presence of adsorption and the small pore volume of the samples.

More work is required to better understand the role of the different phenomena acting simultaneously when CO_2 is exchanging mass with preserved sidewall cores from unconventional liquid reservoirs.

Acknowledgments

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