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Effect of Stratification on Segregation in Carbon Dioxide Miscible Flooding in a Water-Flooded Oil Reservoir

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Abstract

Oil reservoirs are subjected to tertiary recovery by deploying any enhanced oil recovery (EOR) technique for the recovery of left over oil. Amongst many EOR methods one of the widely applied worldwide is CO_2 flooding through miscible, near miscible or immiscible displacement processes. CO_2 flooding process responds to a number of reservoir and fluid characteristics. These characteristics have strong effect on overall efficiency of the displacement process. Better understanding of the effect of different characteristics on displacement process is important to plan an efficient displacement process. In this work, the effect of stratification resulting in gravity segregation of the injected fluid is studied in an oil reservoir which is water-flooded during secondary phase of recovery. Sensitivity analysis is performed through successive simulation on Eclipse300 (compositional) reservoir simulator. Process involves the continuous CO_2 injection in an oil reservoir with more than $1/3^{rd}$ of original oil in place left after water flooding. Reservoir model with four different permeability layers is studied. Four patterns by changing the arrangement of the permeabilities of the layers are analysed. The effect of different arrangement or stratification on segregation of CO_2 and ultimately on the incremental oil recovery, is investigated. It has been observed that out of four arrangements, upward fining pattern relatively overcame the issue of the segregation of CO_2 and consequently 33% more oil with half injection volume is recovered when compared with the downward fining pattern.

Key Words: enhanced oil recovery; carbon dioxide flooding; segregation; reservoir simulation; compositional modelling; slim-tube simulation

1. Introduction

Oil reservoirs usually have 5 types of natural production mechanisms which dictate their life under primary conditions [1,2]. These mechanisms along with the range of oil recovery factors are shown in Table 1

It shows the solution-gas drive reservoirs are the most attractive for the application of artificial recovery mechanisms (secondary or tertiary). Figure 1 is showing the overall life cycle of a typical oil reservoir in terms of time from lease to abandonment [3]. While Figure 2 depicts the duration of production, development and sales in terms of recovery mechanisms applied throughout the life of a reservoir.

It has been clear from the Figure 2 that EOR targets the remaining oil in place after the previous modes of production become uneconomical, and acts as to revitalize the mature field [4].

Various EOR methods have been found and continued to develop with time, but miscible gas and thermal flooding are the industry mostly applied EOR methods as indicated from the survey [5]. Out of 315 EOR projects, 152 were miscible gas and 138 were thermal. Only 25 remaining projects used other EOR technologies combined. Similarly, 116 EOR projects in the world employed CO_2 under miscible conditions.

1.1 Gas Injection EOR

Though gas injection is the mostly applied EOR method, its performance greatly depend on fluid physical properties that affect flow behaviour in reservoir. Most important are density and viscosity of these gases (section 1.3), although other properties, such as compressibility, solubility in water, and interfacial tension, are sometimes required in calculations.

Table 1: Natural Driving Mechanisms in Oil Reservoirs [1]

Drive Mechanisms	Oil Recovery factors (% of OIIP)		Sor %
	Range	Average	Average
Solution Gas	5 – 30	15	85
Gas cap	15 – 50	30	70
Water	30 – 60	40	60
Gravity drainage	16 – 85	50	50
Combination [2]	> Solution gas, < Gas cap and water		-

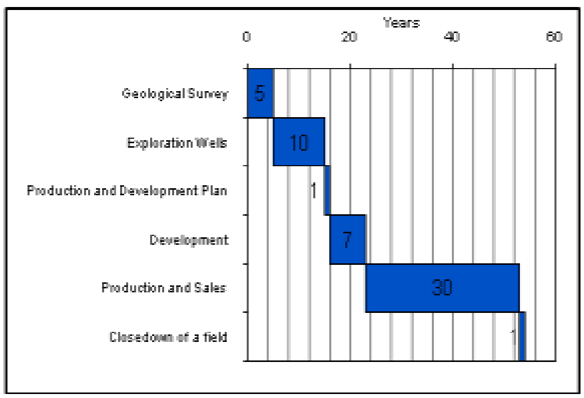

Fig.1: Life cycle of an Oil Field

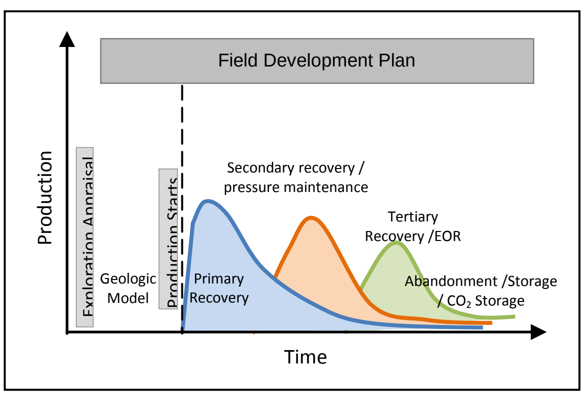

Fig.2: Field life cycle in terms of production behaviour [4]

1.2 Carbon Dioxide EOR

Klins [6] and Jarrell *et al.* [7] have published comprehensive books on carbon dioxide flooding. To distinguish between CO_2 and other gases and to highlight the factors which make CO_2 preferable over other gases, a few sections are described here.

1.3 Properties of CO2

Table 2 incorporates physical properties of CO_2 and other injection gases like N_2, CH_4, C_2H_6 and C_3H_8 at 14.7 psia and 60°F. Note that the density of gaseous CO_2 is much greater than that of gaseous N_2 which means CO_2 is less prone to gravity segregation.

Table 2: Physical properties of injection gases [8]

X	M (lbm/ lbm-mol)	T_c (°F)	P_c (psia)	ρ_{liq} (lbm/ ft^3)	ρ_{gas} (lbm/ ft^3)	μ_{gas} (cp)
CO_2	44.0	87.91	1,071	51.02	0.116	0.144
H_2S	34.1	212.6	1,306	49.98	0.089	0.124
N_2	28.0	-220	507.5	49.23	0.074	0.174
CH_4	16.0	-117	666.4	18.71	0.042	0.108
C_2H_6	30.1	89.92	706.5	22.21	0.079	0.009
C_3H_8	44.1	206.1	616.0	31.62	-	0.008

At high pressures, density of CO_2 increases and approaches to that of liquids (figure 3), yet its viscosity remains quite low staying in the same range as gases (figure 4). These characteristics make CO_2 uniquely qualified for miscible gas EOR.

1.4 Mobility and Gravity Force Considerations

As discussed in section 1.3, CO_2 has greater density and viscosity than other EOR gases, yet it offers certain problems like unfavourable mobilities and gravity override. To improve mobilities certain thickeners are added, and injection rate can be optimized in-order to control segregation to some extent [9]. Both processes also depend on porous medium to study which is the aim of this study.

1.5 Miscibility and Minimum Miscibility Pressure (MMP)

"Minimum miscibility pressure is the minimum pressure in condensing gas drive process at which interfacial tension of injected and native fluids become zero under single phase conditions (i.e., miscibility is achieved) and theoretically 100% oil recovery can be expected" [9-18]. At pressures and temperatures higher than critical point, CO_2 exists as dense phase that easily becomes miscible with oils. Even at immiscible conditions CO_2 can improve oil recovery by one of several mechanisms such as:

a) Reduces oil viscosity

b) Lowers oil density

In general, miscibility between fluids can be achieved through one of two mechanisms: First Contact Miscibility (FCM), or Multiple Contact Miscibility (MCM) through vaporising gas drive or condensing gas drive. A detailed discussion of how these mechanisms occur in reservoir at molecular level are beyond scope; suffice is to say that CO_2 develop miscibility in multiple contacts with both vaporising and condensing gas drive [19-21], again a distinctive feature makes it an ideal miscible EOR agent.

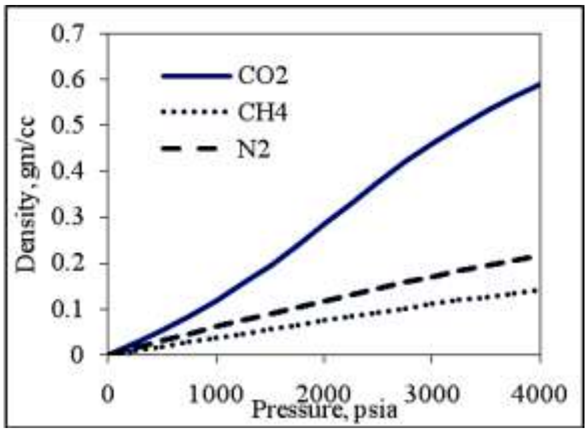

Fig.3: CO_2, CH_4 and N_2 densities at 217.5°F (Generated by EOS)

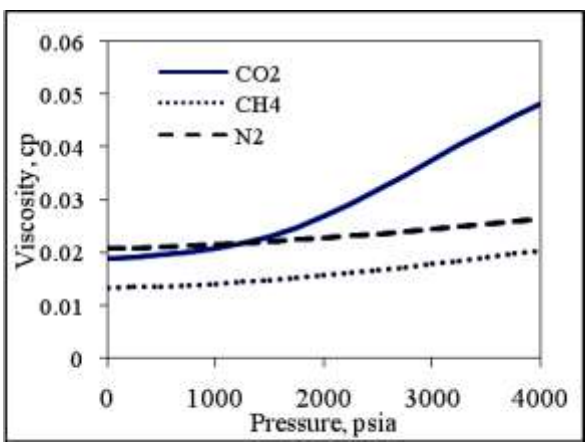

Fig.4: CO_2, CH_4 and N_2 viscosities at 217.5°F (Generated by EOS)

2. Objective

Though CO_2 at high pressures has much higher density than other EOR gases almost approaching to liquids, nonetheless, it is subjected to gravity segregation because the liquids it encounters in the reservoir are heavier. This study was undertaken to get a basic and general understanding. How does stratification affect CO_2 segregation, and consequently, incremental oil recovery? This work addresses this with different perspective than other earlier studies. Table A in Appendix outlines the distinguishing features of this and two earlier studies [22, 23].

2.1 Case Description

A real producing oil reservoir structure with depth from 5,350 to 5,750 feet was arbitrarily divided into of different permeability and same porosity. Figure 5 depicts structure of the subject reservoir. Table 3 illustrates the permeability stratification schemes. Net thickness of the play was 25x4 feet with vertical communication of 1/10th of horizontal. Total PV is 148 MM rb and 25x46x4 grids of 200x200x25 ft^3 were used.

Table 3: Permeability Stratification Schemes (mD)

	P1	P2	P3	P4
Layer 1	500	500	75	75
Layer 2	250	125	250	125
Layer 3	125	250	125	250
Layer 4	75	75	500	500

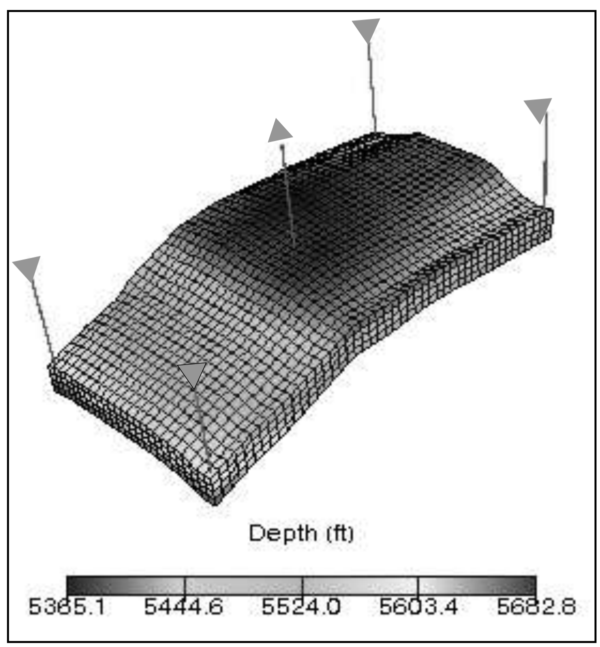

Fig.5: 3D reservoir structure with depth scale

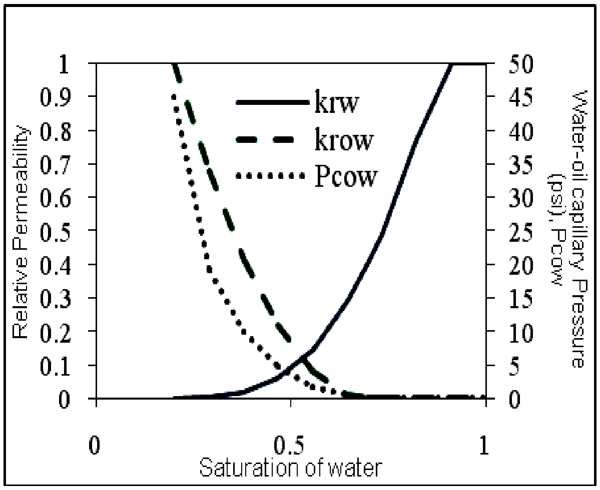

Fig.6: Water, oil and rock interactive properties

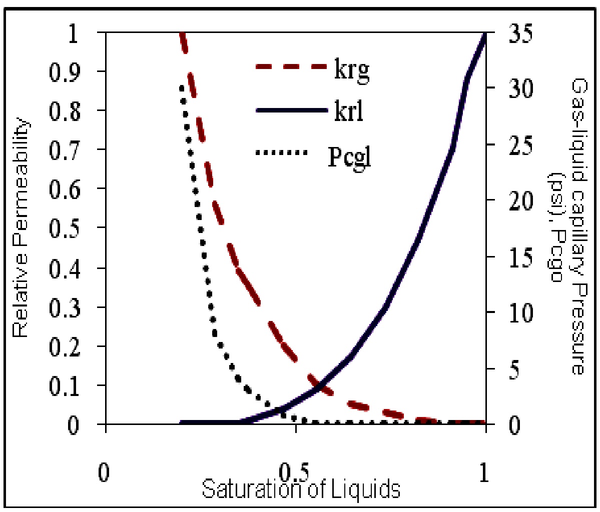

Fig.7: Liquids, gas and rock interactive properties

Figure 6 and 7 show relative permeability and capillary pressure data which was taken from a miscible flood project [24]. Apparently, the rock is intermediate wet with a well sorted pore structure.

An under-saturated crude from West Texas [25] was regressed to Peng-Robinson EOS.

Reservoir has four injectors at corners and a producer at the centre (Figure 5). Firstly, it is depleted under primary mechanism for about 5 months till the bottom-hole pressure at production well BHP reaches bubble point. Then, waterflooding is commenced at 3,500 psia and continued for a total producing life of 10 years.

2.2 Selection of Injection Gas

Table 4 shows MMPs for the injection gases considered.

Table 4: MMPs for Injection gases at 217.5 °F

Gas	**MMP** (psia)
100% CO_2	3,250
100% N_2	>14,000
100% CH_4	7,270
50%CH_4, 50%CO_2	5,410
Separator gas	3,840

MMPs for various gases with crude in consideration were estimated from slim-tube simulations. Figure 8 represents recovery vs. pressure plot for pure CO_2 having the lowest MMP. CO_2 was injected at 3,500 psia slightly higher than MMP in-order to maintain miscibility throughout the play.

3. Results and Discussion

Continuous CO_2 was injected for 10 years in each of the four permeability configurations shown in Table 3, after water-flood. Incremental oil recovery results are presented in Table 5; with more detail in Table B in Appendix.

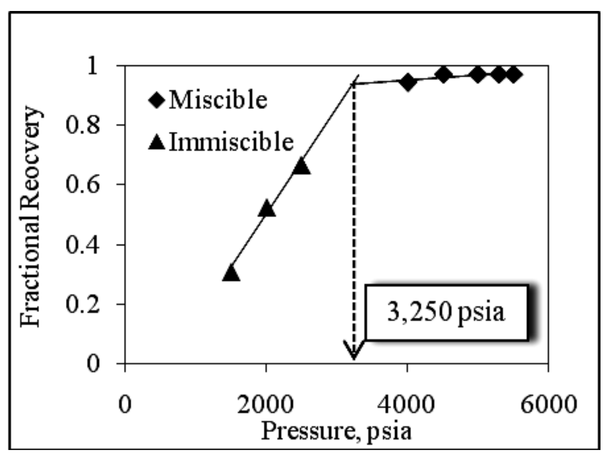

Fig. 8: Slim-tube simulation for MMP_{CO2}

It can be seen from table 4 and B that for upward fining (P4), which is offensive to gas overriding nature, exhibited greatest recovery in case of CO_2, while lowest in case of water flooding because of favourability. However the highest overall recovery was 65.64% in the case of downward fining (P1), majorly due to opposition to under-riding property of water which is also a relatively wetting phase. On the other hand CO_2 found favourable medium to override and thus displaced second lowest oil.

Most interesting behaviour was observed in the case of P2, where water-cut was lowest and GOR was highest. 125 mD at higher position caused a delayed water breakthrough as water has under-ride nature. In the case of CO_2 in P2, 125 mD was placed higher and below 500 mD. Gas found it extra facile to focus 500 mD more than the layers lied below it and as a consequence, highest GOR was observed which suppressed oil recovery in CO_2 flood.

4. Conclusion

Gravity override was observed in all four different layering patterns (P1, P2, P3 and P4) but the most attractive results were observed in upward fining case (P4) for minimum HCPV of CO_2 injected and most interesting for P2 with earliest breakthrough and least oil recovery. Thus concluded from this task that CO_2 as a displacing gas is dependent on the permeability layering order and exhibits segregation in downward fining cases where it can be controlled in following ways:

a. Simultaneously injecting CO_2 with water (SWAG)

b. Alternate slugs of CO_2 and Water (WAG)

c. CO_2 slug followed by continuous injection of water

Table 5: CO_2 Incremental oil recovery after Water flood

Pattern	Oil recovery, (%)	S_{orco2} (fraction)
P1	6.74	0.258
P2	6.18	0.262
P3	7.89	0.270
P4	9.97	0.265

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6. Nomenclature

BHP	=	bottom-hole pressure, psia
EOR	=	enhanced oil recovery
EoS	=	equation of state
FCM	=	first-contact miscibility
FOE	=	oil recovery factor
GOR	=	gas-oil-ratio, MSCF/STB
HCPV	=	hydrocarbon pore-volume
k	=	permeability, mD (milli Darcy)
krg	=	relative permeability to gas
krl	=	relative permeability to liquids
kro	=	relative permeability to oil
M	=	molar weight, lb_m/lb_m-mole
MCM	=	multiple-contact miscibility
p_b	=	bubble point pressure, psi
P_c	=	critical pressure, psia
Pcgl	=	gas-liquids capillary pressure, psi
Pcow	=	oil-water capillary pressure, psi
PV	=	pore volume
Q_o	=	oil rate at the end, STB/D
SWAG	=	simultaneous water and gas injection
T_c	=	critical temperature, °F
WAG	=	water-alternating-gas
WCT	=	water cut
WOR	=	water-oil-ratio, STB/STB
X	=	component
μ_{gas}	=	viscosity of gas, cp
ρ_{gas}	=	density of gas, pcf (lb_m/ft^3)
ρ_{liq}	=	density of liquid, pcf (lb_m/ft^3)

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Appendix

Table A Distinctions of Warner's [21], Shedid's [22] and "This Work"

	[21] Base Case	[22] Layered cores	This Work (all cases)
	Reservoir Properties		
Layers	5	3	4
k_h, **mD**	100 (arithmetic)	2.88, 6.74/7.52, 12.36	500, 250, 125, 75 (4 cases)
ϕ, **fraction**	0.20	0.1042 – 0.1271	0.15
Pay thickness, feet	25 (5 each)	N/A	100 (25 each)
Well Spacing (5-spot pattern), acre	40 acres	N/A	639
Depth, feet	4000 (Uniform)	N/A	5350 to 5750 (dipped)
Reservoir Temperature, °F	113	250	217.5
Initial Reservoir Pressure	2,100 psia	3,700 psig	4,138 psia
	Fluid Properties		
Oil Locality	Mid-continent	Middle East	West Texas
Oil API	38.7	Not mentioned	44.5
MMP pure CO2, psia	1300	3,800 (averaged)	3250
Bubble point pressure, psia	338	3,723 psig	2850
	Tool of Study		
Model	Numerical 4 – Component (Modified Black Oil)	Experimental (Cores)	Numerical Multi-component (Compositional)
Miscibility Mechanism	First Contact	Multiple contact	Multiple Contact
Mixing Parameter	0.8	N/A	Not Applicable
	Operational Aspects		
Primary Depletion	Allowed reservoir pressure to drop below p_b by 623 psia	N/A	Terminated when well BHP reached just above p_b
Waterflood	Pressure raised to 1,900 psia from 260 psia	N/A	From 3000 psia Reservoir Pressure raised to 3100 to 3280 psia (4 cases)
Secondary Oil Recovery, %	43.56	N/A	54.70 to 58.99
CO_2 injection	25% HCPV followed by water	15, 30 and 45% HCPV followed by Water	Straight
Waterflood terminated at WOR	30	N/A	Not applicable
CO_2 Flood terminated at GOR, MSCF/STB	Not applicable	N/A	1 to 105 (4 cases)

Table B: Water And Carbon Dioxide Flooding Results (total time = 20 years)

	Sor		**RF,** (%)		**WCT,** (%)		**GOR** (SCF/STB)	**PVI** Fraction		**Recovery** (MMSTBO)
Flood	**Water**	**CO_2**	**Water**	**CO_2**	**Water**	**CO_2**	**CO_2**	**HCPV**	**PV**	**CO_2**
P1	33.7	25.86	58.90	6.74	2	91.92	107,021	1.51	0.51	5.28
P2	33.6	26.17	58.99	6.18	**1.5**	**92.22**	**112,390**	1.56	0.52	**4.85**
P3	36	27	55.99	7.89	53.8	70.34	9,607	0.77	0.28	6.20
P4	37	26.53	54.70	9.97	59.8	49.13	3,029	0.72	0.27	7.83