International Journal of Advanced Biotechnology and Research (IJBR)
ISSN 0976-2612, Online ISSN 2278–599X,
Vol-8, Issue-2, 2017, pp489-499
http://www.bipublication.com

Research Article

Experimental Investigation of Gas Injection Enrichment on the Increasing of Oil Recovery Factor and Optimize Its Efficiency

Afshin Davarpanah[1], M. Mehdi Nassabeh[2] and Masoud Kakoli[3]

[1, 3] Department of Petroleum Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran
[2]Department of Petroleum Engineering, Faculty of Engineering and Technology, Omidiyeh Branch, Islamic Azad University, Omidiyeh, Iran
*Corresponding Author:Afshindpe@gmail.com

ABSTRACT

Hydrocarbon reservoir is a porous and permeable structure in underground that are placed natural accumulation hydrocarbons in a liquid or gas forms and they are isolated by non-permeable rocks from the surrounding environment. In more concrete description can be likened hydrocarbon reservoirs to a full air balloon that shell of the balloon plays the same role as non-permeable rocks upon piercing balanced environment the reservoir fluids (like air when is exited from balloon quickly) push into the well by hydraulic forces. Although the power of this natural drift reduce along the production of the reservoir. As is said, for instant One of the basic parameters for designing miscible gas injection is determining the minimum concentration of gas injection (MMC). The intermediate concentration of components should be similar that the amount of efficiency displacement reaches to maximum value. During the one-dimensional flow that gas flow rate closes to gas critical velocity, oil recovery reach to the maximum value. Although this method has been successfully applied in many carbonate reservoirs, studies and experiments have shown that injected carbon dioxide chose the fracture path and breakthrough operates quickly. Therefore, injection efficiency reduces consequently.

Keywords: Carbonate reservoirs, injection gas concentration, carbon dioxide, recovery factor increasing

1. INTRODUCTION

When a reservoir were being drilled, firstly it was produced by the natural mechanisms. Natural mechanisms provided the substantial energy to push the fluid mainly included oil and gas to the surface. Oil expansion is a very important part among those mechanisms if without availability of other artificial introduced energy. The rock and fluids expand due to their individual compressibility [1,2]. Since the fluid was expanded and the matrix pore volume was imbibed by the surrounding fluid, the reservoir pressure was plunged. As a result, the crude oil and water will be forced out of the pore space to the wellbore [9]. If the natural energies couldn't provide appropriate power to transfer the oil and gas to the surface, we should use enhanced oil recovery methods like gas injection, water injection and etc. to alter the dead well to a productive well with high efficiency. Injection of organic and inorganic gases into the reservoir is used during secondary and tertiary recovery of oil in order to maintain the balance of the reservoir energy. Gas methods involve blocking the action of capillary forces due to partial or complete mixing of the gas with oil. Process stability is achieved by alternating injection of bursts of gas, gas and water or a gas - water mixture. Pure gas treatment is applied in the case of vertical oil displacement or formations with low permeability where flooding is not applicable. Gas methods enable to increase the production of oil by 5–19% comparing to ordinary flooding applied during secondary recovery [10, 11]. Iranian reservoirs have decline in natural reservoir pressure and production rate for the wells about 8-10 percent annually (Production rate for wells with low reservoir pressure drop is directly related). Production rate gradually reduce with the continuous drop in reservoir pressure, until the normal production of the reservoir will not be profitable. This procedure occurs when the reservoir oil recovery is relatively low. The recovery for reservoir is about 15-20 percent; in other words, 80 to 85 percent of oil remain in reservoir. So new advanced methods and techniques require to produce remained oil in reservoirs. As a result, we can divide the production process of a well into two categories (without that, this classification refers to method of reservoir production):

- ✓IOR or Improved Oil Recovery
- ✓Enhanced Oil Recovery

1.2 Primary Recovery

Primary recovery or natural production is applied for oil extraction under natural driving mechanisms in reservoir without the use of external energy such as gas and water. As it mentioned before, a reservoir has economic production for a short period. In the natural production of reservoir, oil drift is run due to certain mechanisms, we will express them as below:

- Rock and Fluid expansion
- Solution Gas Drive
- Gas Cap Drive
- Water table Drive
- Gravity Drive

1.2.1 Rock and Fluid expansion

In this mechanism the weight of the upper layers pressure on the formation reservoir and fluid expansion it causes oil drift into the well

1.2.2 Solution Gas Drive

Naturally, oil have amount of dissolved gas in pressure and temperature reservoir condition which is released by production. So it can said that the volume of oil in reservoir conditions is greater than the volume of oil on surface of Earth. It might seem that in this case, this phenomenon is explained regardless of different temperature and formation pressure with earth surface. In this case, reduction and surge in volume, counteract each other effects usually, so it can be deduced that the most important factors of oil volume change from formations to surface is dissolved gas in oil. The ratio of oil volume in reservoir temperature and pressure condition to volume of oil in surface temperature and pressure condition is defined as formation volume factor which is always greater than one according to the preceding description. Due to reservoir production, pressure drops consequently, if this pressure drop continue until the pressure reach to saturation pressure, the value of total dissolved gas is released under reservoir conditions that expansion of this gas drive oil into a well.

1.2.3 Gas Cap Drive

In some formations a gas cap is above the oil reservoir, that expansion of this gas cap at reservoir production time pushes oil from top to down like a piston. Certainly, if gas cap be bigger, the reservoir oil recovery will be higher.

1.2.4 Water table Drive

Against the method of gas drive, a water layer can be visualized which is drive into a well from the bottom of oil formation like a piston, instead of the gas forcing from top to the fluid (oil) and produce natural production. It should be noted that in natural oil production, rock and fluid expansion and dissolved gas in the reservoir rock act as a driving force into the well. But reservoirs can be existed both or one of two factors (gas cap or aquifer) or even none of them.

1.2.5Gravity drainage

When the height of reservoir fluid column is large and vertical permeability reservoir is relatively high, in this case, gravity drainage is one of the important mechanisms that is happened.

1.3 Enhanced Oil Recovery

In some cases that the fluid (oil) enter in the bottom of the well and the fluid pressure in the bottom of the well is not capable to bring them to wellhead, other techniques such as gas lift (gas is injected from the surface into the well and this gas with well oil creates mixed miscibility that the density is less than primary oil density and can be transmitted oil to wellhead with that bottom pressure) or down-hole pumps (the oil is pumped from the bottom to wellhead by this device) is used. But, this technique is not mentioned as one of EOR methods. Certainly, enhanced oil recovery (EOR) methods are named as techniques that the fluid inject into the reservoir and this process energize the fluid so, the aim of these methods, is reducing amount of waste oil reservoir. These methods are divided into two categories:

- ✓ Secondary Recovery
- ✓ Tertiary Recovery

1.3.1 Secondary Recovery

This method is the addition of external energies without any change in the physical fluids and reservoir rocks properties. In simple terms, the injected fluid has only pusher and follow-up role. It should be noted, although this method is used in air injection technique that has been the cheapest and the most accessible material, in a few cases the air is used as an injection fluid up to now. Air injection, although increase production for a short time usually, creates many operational problems quickly. Many of problems arising in air injection due to presence of oxygen in that. Because oxygen is highly reactive and creates numerous difficulties in wellhead facilitating and in reservoir. Some of these problems include:

- Spontaneous ignition of oil near injection wells
- Corrosion (the most important factor is oxygen)
- emulsions forming

1.3.2 Tertiary Recovery

The external energy is applied to reservoir and changes in the basic physical and chemical properties of reservoir fluid are occurred consequently. In simple terms, in this procedure injected fluid leads to EOR increase by changing the properties of the fluid system (such as viscosity reduction or changing cohesion between rock and fluid)

Tertiary operations can be divided as follows:

- Miscible Flooding with Gas
- Chemical flooding
- Thermal processes
- Foam Processes
- Micro injection Processes (micro injection is known under this title "Microbial Enhanced Oil recovery" that is separated from "EOR".

In this method, microbes and nutrients are injected into a well and these microbes under some condition produce acids which are used to solve the carbonate rocks or produce gas raising the reservoir pressure or decreasing oil viscosity.

1.4 Gas Injection

As is mentioned gas injection into reservoirs is one of EOR methods which is placed in Tertiary Recovery or Secondary Recovery. If gas is injected before water injection it put in secondary Recovery Phase but if is injected after water injection is placed in Tertiary Recovery category.

Gas injection is divided into two categories generally:

1. Miscible gas injection
2. Immiscible gas injection

Gas injection method is operated in miscible and immiscible process. In miscible method, natural gas becomes rich by adding middle hydrocarbons C_2 to C_6, so that the enrichment part of injected gas that is injected at the beginning time, has been mixed with reservoir oil and guide that from inside of reservoir rock pores to production well. Moreover, the recovery efficiency in this method is the maximum percentage and if the reservoir rock has homogeneous properties and also permeability is adequacy, we can achieve to 65 to 75 percent of the remaining oil volume. In miscible injection, the reaction occurs between injected fluid and hydrocarbons. This reaction creates hydrocarbons with intermediate molecular structure (neither heavy nor light). The mechanism of this type of injection involves gravity decrease between oil and reservoir rock, pressure increase by injected material and lightingof hydrocarbons in the reservoir. In immiscible method, gas is injected into oil reservoirs and this injection is relatively cheap furthermore this procedure is operated in number of onshore and offshore reservoirs oil. In this method, the injected gas is compressed at the top of the reservoir and increases the reservoir pressure moreover, facilitates the movement of oil. In immiscible injection, this procedure is occurred between injected material and underground hydrocarbons. The mechanism of this Oil movement, in this type of injection is generated by pressure production of injected material. It should be noted that the injected gas is not the type of hydrocarbon compounds exactly.so, it can be used other components. In industrialized countries, the gases from large industrial facilities which is the most portion of them is carbon dioxide, is used for injection. In this method, the efficiency and environmental benefits are even higher than injection of hydrocarbon gases.

1.4.1 The importance of oil reservoirs injection:

Gas injection in oil fields is one of the top priorities of Oil Companies in context of quality target. This major is important for several reasons:

– The necessary of hydrocarbon resources protection for posterity rights.
– The necessary of national wealth preservation providing long-term investment in oil section and other sectors of the economy and the strength of countries economic infrastructure.
– Dependence of countries economy on revenues from crude oil exports

1.4.2 Evaluation of oil fields Potential for CO2 injection:

Generally, the first step in initial studies of CO2 injection feasibility in oil reservoirs is target reservoirs recognition with good potential for injection and having the following general criteria:

– Proximity to source of CO2
– Field Location (onshore / offshore)
– field residual oil in place
– Production History and static and dynamic models accessibility
– field fluid properties
– Wells Manufacturing Index
– field surface and wellhead installations
– costs and project economics Anticipation for producing additional barrels of crude oil

Table 1): efficient parameters for CO2 injection in EOR project

effective parameters in Project success	Wt.%
Light oil percentage	24
Residual oil saturation	20
Reservoir pressure gradient with MMP	19
Temperature	14
Oil layer thickness	11
Permeability	7
reservoir Dip	3
Porosity	2

1.5 The effect of injected gas enrichment in recovery factor increase in proposed oil reservoir:

In the laboratory, usually (MMC / MMP) processes are operated by slim tube, the tube length and diameter is 20 m and 0.5 cm respectively that is filled by sand or spherical fine glass particles uniformly. The slim tube is used to measure MMC that the transmittance of porous media must be appropriate and efficient. Used Slim tube features is shown in the table (2).

Table 2) features of Slim Tube:

tube length	2115 cm
pipe outer diameter	6.35 mm
pipe internal diameter	3.77 mm
pore volume of porous media	8.7 Darcy
Slim tube porosity	30.8%
transmittance of porous media	8.7 Darcy
Maximum working pressure of slim tube	10,000 feet
The maximum tolerable temperature	175 ° C
Glass particle diameter	149-105 micrometers

Removal dead oil ratio (without gas) is 2.1 times of pore volume after injection. Generally, oil recovery is increased rapidly by pressure surge or intermediate combinations change and reaches to the point which is observed no much increase on recovery by pressure surge or intermediate combinations change. In this study, 4 different gas samples injection in reservoir pressure (4100psig) and temperature (215 ° F) is performed on oil miscibility of Reservoir (B) with slim tube. Moreover, Gas condensates contain high levels of heavy components. Thus, it doesn't be single-phase with no volume ratio of gas (A). Therefore, associate gas of condensate gas in reservoir (A), with 53 methane mole percent is used for enrichment of gas (A). Miscible gas injection in oil in laboratory studies is commonly used that, the ultimate oil recovery reach to higher than 90 percent in slim tube process. So, the minimum concentration of gas miscibility is determined by this method. In this study, two gases are used along increasing the concentration of intermediate components of gas (A) and enrichment of that with associate gas of condensate gas (A) in different proportions volume. Two samples of enriched gas are lighter than the balanced gas oil reservoir (B) and two others samples enriched gas are heavier than the balanced gas. It means that the mole percent of intermediate components (c2) of injected gas are more than the mole percent of balanced gas reservoir (B) and creates a miscible gas-rich in addition, ultimate oil recovery is greater than 90 percent in this method. In this state, the enriched gas after repeated contact with oil reservoir become lighter gradually and some of the intermediate components of the gas in oil reservoir become liquid form. Since the oil in the rear front have more frequent contacts with the new injected gas, more values has been mixed with intermediate gas components and become miscible form earlier with gas. In this study, 4 enriched gas samples obtaining from condensate associated gas in reservoir (A) with separator gas of reservoir (A) with volume ratio of 3.8, 2.5, 0.8 and 0.25 are used, respectively. In each experiment, oil Recovery is measured after injection of 1.2 times of pore volume of injected enrich gas.

1.5 Oil and gas injection characteristics

Oil reservoir is (B) oil reservoir in all miscibility experiments of oil that the full analysis of bottom holed oil (well stream) is shown in table (3). Bubble point pressure of Oil reservoir (B) at temperature of 215° F is 3631 Psi and gas-oil ratio (1021 SCF/STB) is measured at the start of all experiments.

Table 3): full analysis of bottom holed oil (B)

Mole (percent)	components	Number
1	N2	0.204
2	C1	43.174
3	CO2	0.260
4	C2	7.286
5	C3	4.739
6	iC4	0.915
7	iC4	2.483
8	iC5	1.396
9	nC5	1.738
10	C6	4.060
11	C7	2.766
12	C8	4.176
13	C9	3.686
14	C10	2.209
15	C11	1.658
16	C12	19.250

The measured molecular weight: 89.63 grams per gram mole.

2. Methodology of work

2.1 Gases injection:

Used gas for experiments is a mixture of gas (A) with 85 mole percent of methane and associate gas of condensate gas (A) with 53 mole percent of methane. That, the complete analysis of these two gases note in tables 4 and 5. Also, the enriched composition of gases are used in this experiment is as follows:

i. **The injected gas composition of first experiment:**

It contains one volume of associate gas of condensate gas (A) and 4 volume of gas (A) which is contained 77.85% mole of methane and full analysis is shown in table (6).

ii. The injected gas composition of second experiment:

It contains 2.5 volume of associate gas of condensate gas (A) and one volume of gas (A) which is contained 66.18% mole of methane and full analysis is shown in table (7).

iii. The injected gas composition of third experiment:

It contains 0.8 volume of associate gas of condensate gas (A) and one volume of gas (A) which is contained 74.93% mole of methane and full analysis is shown in table (8).

iv. The injected gas composition of forth experiment:

It contains 3.8 volume of associate gas of condensate gas (A) and one volume of gas (A) which is contained 59.01% mole of methane and full analysis is shown in table (9).

2.2 Experiment demonstration:

The aim of this study is measuring and determining the Minimum Miscibility Concentration of injected Gas containing gas (A) and associate gas of condensate gas (A) due to injection in reservoir (B). For this purpose four oil displacement experiments with 4 samples of enriched gas is defined to displace oil with 4 volume ratio of associated gas of condensate with gas of separation device (A) including 3.8, 2.5, 0.8 and 0.25 at a pressure of 4100 psi and temperature of 215° F.

Before starting Miscibility experiments, pore volume, porosity percent and the permeability of slim tube at 215 ° F in different tests are measured by toluene.

After the end of each test, pore volume of slim tube is washed by toluene solution with several times volume of porous media to ensure the absence of any residual oil deposition in slim tube and device becomes ready for further test. Moreover, Special cylinders and slim tube is located in all stages, injected gas, oil of tests are placed in air bath and the temperature is controlled at 215 Fahrenheit degrees.

Table 4) gas (A) full analysis

Number	Component	Mole (%)
1	N2	0.152
2	C1	84.919
3	CO2	2.764
4	C2	7.130
5	C3	2.761
6	iC4	0.531
7	nC4	0.861
8	iC5	0.349
9	iC5	0.287
10	C6+	0.247

The measured molecular weight: 19.7 grams per gram mole.

Table 5) Full analysis of associate gas of condensate gas of reservoir (A)

Number	Components	Mole (%)
1	N2	0.07
2	C1	53.028
3	CO2	3.028
4	C2	13.988
5	C3	11.075
6	iC4	2.981
7	nC4	5.920
8	iC5	2.788
9	iC5	2.718
10	C6+	4.404

Gas average molecular weight: 32.26 grams per gram mole.

Table 6) Full analysis of enriched gas for first stage MMC in 4100 psig pressure and °F 215 temperature

Number	Components	Mole (%)
1	N2	0.134
2	C1	77.85
3	CO2	2.82
4	C2	8.65
5	C3	4.604
6	iC4	1.074
7	nC4	1.98
8	iC5	0.89
9	iC5	0.83
10	C6+	1.17

Gas average molecular weight: 22.54 grams per gram mole

Table 7) Full analysis of enriched gas for the second stage MMC in 4100 psig pressure and °F 215 temperature

Number	Components	Mole (%)
1	N2	0.104
2	C1	66.18
3	CO2	2.92
4	C2	11.16
5	C3	7.65
6	iC4	1.97
7	nC4	3.83
8	iC5	1.78
9	iC5	1.72
10	C6+	2.69

Table 8) Full analysis of enriched gas for the third stage MMC in 4100 psig pressure and °F 215 temperature

Number	Components	Mole (%)
1	N2	0.13
2	C1	74.93
3	CO2	2.85
4	C2	9.28
5	C3	5.36
6	iC4	1.3
7	nC4	2.44
8	iC5	1.112
9	iC5	1.05
10	C6+	1.528

Gas average molecular weight: 23.67 gram per gram mole

Table 9) Full analysis of enriched gas for the fourth stage MMC in 4100 psig pressure and °F 215 temperature

Number	Components	Mole (%)
1	N2	0.1
2	C1	59.01
3	CO2	2.97
4	C2	12.7
5	C3	9.52
6	iC4	2.52
7	nC4	4.97
8	iC5	2.33
9	iC5	2.26
10	C6+	3.62

Gas average molecular weight: 30.01 grams per gram mole.

The enriched gas is made firstly in all experiments, in this case, it should be ensured about single-phase of gas liquids (A) then one liter of it transfer to 2-liter cylinders in single-phase form by reducing the 2-liter cylinder to atmospheric pressure, all associated gas components are isolated in several stages. The analysis is conducted by gas chromatography device in all stages. Moreover, this process is checked by associated gas of liquid (A) measuring and reporting before. Then specific volume of associated gas of condensate gas is prepared and add to specific volume of gas (215° F and 4100 Psi). In addition, Gas analysis is determined by gas chromatography device. Considered gas is prepared as Enriched gas for injection and placing in injection model. At first the porous media of slim tube is filled by toluene in all displacement tests then is placed in the pressure test to establish reservoir pressure and temperature for overnight. Toluene is displaced by oil without gas and then live oil reservoir (B) at temperature of 215 Fahrenheit degrees and test pressure with a flow rate of 10 cc/hr with the 1.5 times of pore volume of slim tube. The pressure of all miscibility tests is above the reservoir bubble point pressure also, input and output of slim tube pressure is measured with numerical precision ± 5psig. From the start of each permeability experiment of porous media, the GOR of oil reservoir is measured inside the slim tube with associated gas of oil analysis. Gas injection velocity is selected 7.1 cc/hr in all experiments displacement and in each test, gas injection is continued about 12 hours continuously with 1.2 times of pore volume and sampling of oil and gas is performed from the output of slim tube and after the oil and gas separator without interruption. At each stage oil weight and gases volume are measured. Also, the density of produced fluid at reservoir pressure and temperature is registered permanently by densitometer device placing at the end of the slime tube before oil and gas exiting along the flow path, and the time of reaching of injected gas to the end of the slim tube is shown furthermore, Exhaust gas samples at different times is sent for analysis of components to gas chromatography unit. Also, different Produced Oil samples are collected and their volume, weight and density measure and after gas injection to 1.2 times of pore volume, injection operation stops correctly. At the end of each experiment, final oil production ratio of initial dead oil, break through time, gas-oil ratio (GOR) changes during the test and the amount of produced oil at the different times and percentage of pore volume injection are determined. It can be deduced that if the injected gas is richer, the miscibility is more and break through time occur later moreover, oil production will be higher.

In contrast, the rate of produced gas is lower or change slope of GOR is lower than the pore volume of injected gas. At the end of each test, the available gas in the slim tube is evacuated slowly in several hours up to atmospheric pressure. Then, remained oil without gas in slim tube is moved and washed by solvent toluene at high temperature, about 80 ° C to 5 times of pore volume for 2 to 3 days.

2.3 Investigating on the effect of reservoir parameters in injection.

2.3.1 Carbon dioxide immiscibility.

EOR processes include one or more fluid injection into reservoir. Moreover, Injected fluids and injection processes are supplement of natural energy in reservoir to move oil to production wells thus, their production. As well as the injected fluid interactions occur with reservoir oil and rock collection.

So, more favorable conditions are provided for oil production. These mechanisms can lead to surface tension reduction (IFT), Oil swelling, oil viscosity reduction, reservoir rock wettability and phase behavior changes, etc. these interactions occurring in oil and rock system in the reservoir could be happened due to physical and chemical mechanisms or heat generation and thermal energy.

Nowadays miscible gas injection, thermal and chemical injection techniques categorize in EOR methods.

2.3.2 The most important carbon dioxide properties:

Molecular weight, critical temperature, critical pressure, boiling point temperature, MMP at 170 Fahrenheit degrees with C5+ fluid and molecular weight of 180 gr/mole, viscosity at this temperature and pressure and compressibility factor of this element are 44.0095, 89 Fahrenheit degrees, 1070 Pisa, 350 R, 2500psig, 0.04cp and 0.5 have been reported respectively. In addition, it's density at 170 ° F and pressure of 2500 psi is 0.25 gr/cm3. If carbon dioxide injection is used as immiscible process, density should be considered 0.15 g/cc.

2.3.3Immiscible CO2 injection

Immiscible carbon dioxide injection process is one of the EOR methods that carbon dioxide dissolved in heavy oil and reduces it's viscosity. Not only reducing the dissolved carbon dioxide viscosity, but also, leads to oil swelling. Based on experiments doing in laboratory conditions, the viscosity reduction effect is much more than Oil swelling in oil production.

In addition, not only reducing oil viscosity and Oil swelling effects on reservoir productivity ratio increase but also, other mechanism impact on this issue directly. One of the other mechanism effecting on productivity ratio is surface tension reduction.

According to all effective mechanisms in carbon dioxide injection observing in immiscible form, oil displacement by carbon dioxide injection in immiscible form must be much more effective than natural gas injection.

2.4Investigating on two major effects in immiscible injection to oil production increase:

A) The instantaneous effect due to replacing of oil (oil which is not produced in flooding process) with injected gas carbon dioxide, so, oil production will be increase rapidly.

B) Long-term effects such as, viscosity reduction, swelling and changing in permeability behavior. The second factor of oil production increase has been identified over time and during numerous projects.

2.4.1 Secondary porosity or fracture

In fracture reservoirs or dual porosities due to high vertical permeability and occurring over riding or fast break through, the displacement efficiency decrease consequently.

2.4.2 Mobility

WAG method is used to control mobility moreover, Gas mobility ratio should be less than 1 to increase displacement efficiency.

2.4.3 Depth

Steam injection cannot be used in deep reservoirs for two reasons:

1) High heat dissipation along steam move until contacting with available fluid in the reservoir.

2) The heat of injected steam can be raised to certain extent, otherwise it can be damage to pipes and wellhead equipment.

2.4.4 Injection rate

The efficiency of this method is surged by reducing injected carbon dioxide rate and increasing the number of production wells, if gas injection rate is too high, fingering or channeling process will be occur leading to efficiency reduces of oil displacement. In fact, injection rate increase, is observed by reservoir pressure surge and this occurrence leads to prevent water iterance from lower layers. In addition, the more excessive Gas injection rate leads to reducing oil production rate.

2.4.5 Transmissibility

Channeling will be occur in cases that the transmissibility property is low. So, if carbon dioxide injection rate is constant, Fingering and channeling occurs when transmissibility is low.

2.4.6 Number of wells:

Selection of appropriate number and location of injection wells leads to oil sweep completely and efficiency increase. Base on simulation results of gas injection is obtained:

1. Gravity segregation is one of the main problems of carbon dioxide injection in immiscible state. The injected gas tendency of moving from the top of oil can be reduced by vertical permeability reduction or the presence of shale streaks. So overriding probably is one of the main problems in clean sands with high permeability reservoirs.

2. Water channels (even very small) between injection and production well lead to reaching injected gas to production well and break through is occurred rapidly.

3. RESULT:

1.The minimum miscibility concentration (MMC) of Gas (A) and associate gas of condensate gas (A) with volume ratio of 1.3 of associate gas of condensate gas volume to one volume of gas (A) at 4100 Psi and 215 Fahrenheit degrees is determined.

2. In miscibility tests performing in this study enriched gases are used for injection in oil reservoir that these compounds become liquid form after repeated contact with oil reservoir. Since the oil, placing behind the front have more chance of contact with new injected gas repeatedly, a greater amount of intermediate gas composition (C2-C5) have been mixed and comes to miscibility state with gas sooner. This miscibility state is called Rear Dynamic Miscibility.

3. The composition of the exhaust gases from the slim tube remains constant approximately during different times of gas injection until the break through time, but after break through time exhausted gases change and close to enriched gas composition that in gases which are lighter than balanced gas, the methane percent increases and the percentage of total C2-C6+ decreases moreover, for injected gases which are heavier (richer) than balanced gas of oil (B), the methane percent reduces and the percentage of total C2-C6+ increases consequently.

4. In all miscibility experiments, GOR value increases after break through time rapidly and oil production decreases quickly.

5. For enrichment of gas (A) with condensates of gas (A) in any volume ratio, two fluids do not be single phase forms with each other in addition, the observations show that the gas layer and condensates place always on top of the cylinder

and below gas layer respectively. So, for enrichment of gas (A), associate gas of condensate gas (A) is used in different volume ratio.

6. Whatever the compositions of injected gas is closer to compositions of associated gas of oil testing in this study, better miscibility occurs consequently.

7. The light gas at rates of more than 0.2 of volumetric ratio with condensates gas having heaver compositions, does not be single phase gas form (at ambient and reservoir conditions).

4. CONCLUSION:

Proposed reservoir are generally deep and fracture reservoirs so, the use of immiscible carbon dioxide injection are not successful for two main reasons:

1. Although this method has been successfully applied in many carbonate reservoirs, studies and experiments have shown that injected carbon dioxide chose the fracture path and break through will be happened rapidly. As a result, injection efficiency will be reduced.

2. This method does not use in light oil reservoirs, usually in depths of over 3000ft. Because, the pressure is so high that it can withstand the miscibility pressure. But if reservoir oil is heavy, despite of high depth of reservoir, because of, miscible process is operated difficulty in heavy oils, immiscible injection method is used in this state.

* This method is especially for oil reservoir placing near the carbon dioxide sources and is highly recommended.

* Critical gas saturation and diffusion rate are affecting parameters on oil recovery ratio in fractures so, enough information about these parameters must be available before carbon dioxide injection (WAG method).

REFERENCES:

1. benham, A.L.,Dowden, W.E., and Kunzman, W.J., “Miscible Fluid Disolacement-Prediction of Miscibility”, AIME(1960) 219,229-37.
2. Hutchinsun, C.A., and Braun, P.H.: “Phase Relations of Miscible Disolacement IN Oil Recovery”, AICHE J. (March 1961) 7, 64-67.
3. Latil, M., “Enhance Oil Recovery”, Institute Francis du Petrole Publications”, 1980.
4. Metcalfe, R.S. and Yarborough, L.: “The Effect of Phase Equilibria on the CO2 Disolacement Mechanism”. SPEJ (Agu. 1979) 242-52.
5. Danesh, A., “PVT and Petroleum Fluid Phase Behavior”, Elsevier, 2000.
6. Kou, s.s. “Prediction of Miscibility Pressure Correlation”, SPE 14152, Proc. Of 60^{th} SPE Ann. Conf. (Sept. 1985).
7. Simon, R. and Graue, D.J., “Generalized Correlation for Predicting Solubility, Swelling and Viscous Behavior of CO2- Crude Oil System”, JPT (Jan. 1965) 102-106.
8. Crawford, H.R., Neill, G.H., Bocy, B.J., and Crawford, P.B., “Carbon Dioxide-A Multi-Purpose Additive for Effective Well Stimulation”, JPT (Mar. 1963) 137-242.
9. Rathmell, J.J., Stalkup, F.I., and Hassinger, R.C., “A Laboratory Investigation of Miscible Disolacement by Carbon Dioxide”, SPE preprint no. 3483 (1971)
10. Lawrence J J, Teletzke G F, Hutfilz J M, and Wilkinson JR., "Reservoir Simulation of Gas Injection Processes".Paper SPE 81459 presented at SPE 13th Middle East Oil Show &Conference, Bahrain, 5-8 April (2003) (SPE 81459).
11. Christensen J R, Stenby E H, and Skauge A., "Review of WAG Field Experience". SPE Reservoir Evaluation and Engineering vol.4, no. 2, p.97, April (2001) (SPE).
12. Madhav M. Kulkarni, Dandina N. Rao., "Experimental Investigation of Miscible and Immiscible Water- Alternating-Gas (WAG) Process Performance". The Craft and Hawkins Department of Petroleum Engineering, Louisiana State University, 3516 CEBA Bldg., Baton Rouge, LA 70803, United States, (2005).

13. Haghighat, S A., WAG Modeling in Fractured Reservoirs. Thesis report MTA/PW/04-15 TU Delft, August (2004).
14. Heeremans J C, Delft U. of Technology; T E H Esmaiel, Delft U. of Technology and Kuwait Inst. "Feasibility Study of WAG Injection in Naturally Fractured Reservoirs". Oklahoma, USA. 22-26 April (2006) (SPE 100034).
15. Van Lingen P P, Barzanji O H M, van Kruijsdijk C P J W., "WAG Injection to Reduce Capillary Entrapment in Small- Scale Heterogeneities". Paper SPE 36662, SPE Annual Technical Conference Denver. Colorado, S.S.A, 6-9 October (1996) (SPE 36662).
16. James W. Amyx, Daniel M. Bass, JR, Robert L. Whiting, "Petroleum Reservoir Engineering, Physical ", McGraw-Hill Book Company, Inc.