



## **Improved Oil Recovery by Carbon Dioxide Flooding**

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### **ABSTRACT**

The injection of CO<sub>2</sub> can enhance oil recovery as well as help in mitigating the problem of increased CO<sub>2</sub> concentrations in the atmosphere by storing large quantities of CO<sub>2</sub> for a long period of time. At most reservoir conditions CO<sub>2</sub> is a supercritical fluid with high solvency power to extract hydrocarbon components and displace oil miscibly. ECLIPSE compositional simulator was used in this study to reproduce CO<sub>2</sub> displacement processes. In the Reservoir Simulation Model, certain parameters that are pivotal to the overall output of the process were held constant while others whose contributions are to be investigated were varied in the different runs for a 25 year period and Oil recoveries with respect to the different parameters were evaluated. An incremental recovery was observed for the 25 year period as the reservoir dip moves from 0° to 40° resulting in a 25% additional recovery. Heterogeneity index has inverse relationship with recovery from CO<sub>2</sub> processes. CO<sub>2</sub> evaporates the condensable portion of the fluid giving CO<sub>2</sub> flooding an edge over methane injection. Higher mobility ratios favour more oil recovery. This research shows the additional recovery being expected by the use of CO<sub>2</sub> Enhanced Oil Recovery (EOR). In conclusion CO<sub>2</sub> EOR performance is influenced by reservoir heterogeneity, reservoir dip, mobility ratio of the CO<sub>2</sub> to oil, injection rate, volume of CO<sub>2</sub> available and reservoir fluid type. The reservoir dip favours recovery significantly as the reduced viscosity of the oil is further propelled downward to the completed zone.

**Keywords:** Carbon Dioxide Injection, Enhanced Oil Recovery, Compositional Simulation, Reservoir Dip, Improved Recovery, Heterogeneity

### **I. INTRODUCTION**

The practice of CO<sub>2</sub> injection as a tertiary recovery mechanism has been applied in the industry since early 1950s. One major advantage of CO<sub>2</sub> as a choice fluid in EOR projects is that the fluid is supercritical at most reservoir conditions, being able to extract hydrocarbon components and miscibly displace oil. Carbon dioxide (CO<sub>2</sub>) is one application that has benefits to the environment by the reduction of Carbon dioxide in the atmosphere. Carbon dioxide flooding is a capital intensive project and highly technical in execution and requires a thorough screening criteria before project execution. Diaz, *et al.*, (1996), Carcoana (1982), Taber & Martin (1983), Klins (1984), Martin and Taber (1992) and Baker (2004) amongst others have proposed various screening criteria to be adhered to and applied before the inception of CO<sub>2</sub> flooding. These screening criteria go a long way in reducing the risk of randomly choosing a reservoir without duly certifying that they are qualified to be subjected to such capital intensive project thereby reducing the level of uncertainty.

The interaction between CO<sub>2</sub>, rocks and reservoir fluids varies with type of rock and fluids as well as pressure and temperature. In addition, CO<sub>2</sub> shows more complex phase behavior with reservoir oil than many other solvents. The relatively high solubility in water and the associated reduction in pH will affect the reservoir chemistry depending on the PVT conditions, reservoir fluid and rock composition, Grigg and Siagian (1998).

The two major classifications of CO<sub>2</sub> flooding are miscible CO<sub>2</sub> injection and immiscible Water Alternating Gas (WAG) injection. Miscible CO<sub>2</sub> injection occurs when the reservoir is above the minimum miscibility pressure (MMP) and the flooding is said to be immiscible when it is done below the MMP. The following mechanisms play a role in the recovery of oil by any non-hydrocarbon gas flooding: reduction of oil viscosity, oil swelling, miscibility effects, interfacial tension reduction, crude oil vaporization and injectivity increase.

Enhanced Oil Recovery is also called tertiary oil recovery and is employed when secondary oil recovery is not enough to continue adequate production, and only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the current price of crude oil. (Abadli, 2012). The adoption of this method must be economically justified when compared with a base case of doing nothing.

### **II. WETTABILITY AND RELATIVE PERMEABILITY**

Wetting characteristic of the reservoir rock appear to be the most controlling factor of the operating strategy for an EOR process, but according to McDougal *et al.*, (1997), the precise taxonomy of wettability is still lacking. CO<sub>2</sub> reduces the brine pH, and there are some experimental evidences that it reduces the water-wetness in capillary cells also. Experience from both laboratory tests and studies of field data supports the fact that wettability is critical to CO<sub>2</sub> injection, Rogers and Grigg (2000). Relative permeability occurs because the rock porosity contains multiple phases such as oil, water and gas and it affects the injectivity of CO<sub>2</sub>; therefore, it plays an important

role in the rate at which CO<sub>2</sub> flows in the reservoir.

### III. OPERATIONAL SEQUENCE OF CO<sub>2</sub> FLOODING

CO<sub>2</sub> is directed to injection wells strategically placed within the pattern of wells to optimize the areal sweep of the reservoir. The injected CO<sub>2</sub> enters the reservoir and moves through the pore spaces of the rock, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated oil bank that is swept towards the producing wells.

### IV. MODEL DESCRIPTION AND DEVELOPMENT

ECLIPSE Compositional simulation and pseudo-miscible black oil models was used in this study to reproduce CO<sub>2</sub> displacement processes. A total of 104 reservoir-to-fluid designs to bolster the effect of the contributing factors to the overall performance of CO<sub>2</sub> were investigated. The design entailed building a 30 by 30 by 20 grid cells in the X, Y and Z axis respectively of 100 by 100 by 25ft resulting to 18000 cells. The model has a constant porosity of 25% and a water saturation end point of 10% across all the regions. All the cells are active with no faults. However, the models are hypothetical models built to the Niger Delta geologic representation possessing rock and petro physical properties obtainable in the region. A total of 24 different crudes from Shell Nigeria fields in the Niger Delta were obtained and characterized using ECLIPSE PVTi to generate fluid performance in the simulator. Other designed parameters are as follows:

#### Reservoir Depth:

To generate a robust scenario, the analysis was carried out at three different depths: 5000ft, 10,000ft and 15,000ft. This serves as a guide in obtaining the formation pressure as expressed by Eq. 1, at various reservoir depths which control injection pressure.

$$p_f = 0.052\rho h \tag{1}$$

This has a direct translation on the choice of injection rates of the CO<sub>2</sub> since operation must be within safety limits to ensure that the formation parting pressure is not exceeded. For the three depths investigated, the temperature gradients were estimated using Eq. 2.

$$T_g = 1.67 \text{ }^\circ\text{F}/100\text{ft} \tag{2}$$

#### Reservoir Dip

Five different reservoir dip angles: 0°, 5°, 15°, 30° and 40° were examined.

### V. MODELING RESERVOIR PERMEABILITY

The reservoir permeability was divided into two: (a) Homogeneous permeability distribution; where all the permeabilities of cells in the X and Y directions are similar;

and the Z axis permeability is constant all through the reservoir (b) Heterogeneous permeability distribution where the permeability distribution differs across the reservoir in both the horizontal and vertical directions.

A permutational selection of each of these cases is done and imported into ECLIPSE compositional simulator with the corresponding angle of dip included prior to importing the fluid. PVT simulation model for Equation of State (EOS) tuning process was performed using the Peng-Robinson method.

The performance model developed here is a fractional-flow based screening model. It is based on the Koval method, Koval (1963), for predicting recovery in a secondary CO<sub>2</sub> – flood, to model secondary miscible flooding process modified by Claridge (1972) for aerial sweep in an inverted five-spot pattern.

### VI. MINIMUM MISCIBILITY PRESSURE

In this study, MMP for the twenty four fluids investigated were estimated using Equation 3.

$$MMP = 15.988 * T^{(0.774206 + 0.0011039) + MWC_{5+}} \tag{3}$$

Where:

T = Temperature in °F

MWC<sub>5+</sub> = The molecular weight of pentane and heavier hydrocarbons in the reservoir’s oil. From material balance, the voidage rate is computed as follows:

$$dv/dt = q_o (B_t + (R_p - R_{si})B_g) \tag{4}$$

Where:

dv/dt = Reservoir voidage rate, RM<sup>3</sup>/Day

q<sub>o</sub> = Oil production rate at start of CO<sub>2</sub> injection, (SM<sup>3</sup>/Day)

B<sub>t</sub> = Two phase formation volume factor, (RM<sup>3</sup> / SM<sup>3</sup>)

R<sub>s</sub> = Solution gas ratio ( SM<sup>3</sup>/ SM<sup>3</sup>)

R<sub>p</sub> = Produced gas oil ratio (SM<sup>3</sup> / SM<sup>3</sup>)

B<sub>g</sub> = Gas formation volume factor (RM<sup>3</sup> / SM<sup>3</sup>)

An injection rate that corresponds to the calculated voidage rate was adopted. The surface equivalence of the voidage rate was obtained as follows:

$$Q_{inj.rate} = \frac{Void Rate}{B_{g.CO_2} @ P_{fi}} \tag{5}$$

Where:

Q<sub>Inj.Rate</sub> = Injection rate, SM<sup>3</sup>/Day

Void Rate = Reservoir Voidage Rate, RM<sup>3</sup>/Day

B<sub>g.CO<sub>2</sub></sub> @ P<sub>fi</sub> = CO<sub>2</sub> formation volume factor at formation pressures (P<sub>fi</sub>), RM<sup>3</sup>/SM<sup>3</sup>

## VII. THE HYDROCARBON PORE VOLUME INJECTED (HCPV) AND FRACTIONAL PORE VOLUME (FPV)

The hydrocarbon pore volume injected was estimated by Eq. 6:

$$HCPV = Q_{Inj.Rate} + t_{eff} \quad (6)$$

Where,

$$t_{eff} = 25 * 365 - t_{initial} \quad (7)$$

Where:

$Q_{Inj.Rate}$  = CO<sub>2</sub> injection rate, SM<sup>3</sup>/Day

$t_{eff}$  = Time of effective CO<sub>2</sub> injection, Day

$t_{initial}$  = Time before inception of CO<sub>2</sub> injection, Day

$$FPV = \frac{HCPV}{RSPV} \quad (8)$$

Where:

$FPV$  = Fractional Pore Volume, ratio

$HCPV$  = Hydrocarbon Pore Volume, RM<sup>3</sup>

$RSPV$  = Reservoir Pore Volume, RM<sup>3</sup>

## VIII. CO<sub>2</sub> MOBILITY RATIO

Since the viscosity of CO<sub>2</sub> at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and therefore, oil recovery Campbell (1985). Mobility ratio is defined as the ratio of the mobility of the displacing fluid to that of the displaced fluid. The Mobility ratio of CO<sub>2</sub> to oil is expressed by Equation 9.

$$M = \frac{K_{rcos_2} / \mu_{CO_2}}{K_{rowg} / \mu_o} \quad (9)$$

Where:

$M$  = Mobility ratio of CO<sub>2</sub> to oil

$K_{rcos_2}$  = Relative permeability of rock to CO<sub>2</sub>

$K_{rowg}$  = Relative permeability of rock to oil in the presence of water and gas

$\mu_{CO_2}$  = Viscosity of CO<sub>2</sub>, cp

$\mu_o$  = Viscosity of oil, cp

## IX. RESULTS AND DISCUSSION

Well Placement is very important in this model in order to obtain a prudent drainage pattern for optimum production. Hence, for this system, an inverted 5-spot pattern was used with four production wells and an injector well strategically placed for optimum distribution of the CO<sub>2</sub> in the reservoir as shown in Figure 1. Six key parameters under investigation are: reservoir dip, Heterogeneity index, CO<sub>2</sub> to Oil mobility ratio, Fluid API, Injection rate and Injected volume.

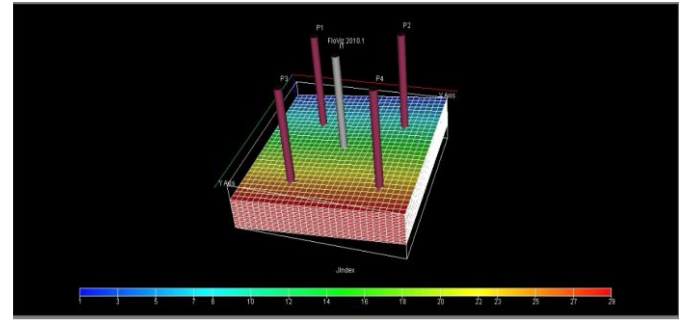


Figure 1 Well Configurations for an Inclined Reservoir (5° Dip)

### ANALYZING EFFECT OF CONTRIBUTING PARAMETERS

The reservoir Dip has a positive contribution to the overall process of CO<sub>2</sub> injection as larger angles favor incremental oil recovery as seen in Figure 2. Reservoir dip has the most significant impact on oil recovery. An incremental recovery is observed as we move from 0° to 40° such that after a period of 25yrs, the presence of dip in the formation of our reservoirs accounts for about 25% additional increase. A reservoir dip of 40° will produce an incremental recovery of 47.3% while a reservoir dip of zero degree achieves 22.5% incremental oil recovery showing a 24.8% improvement.

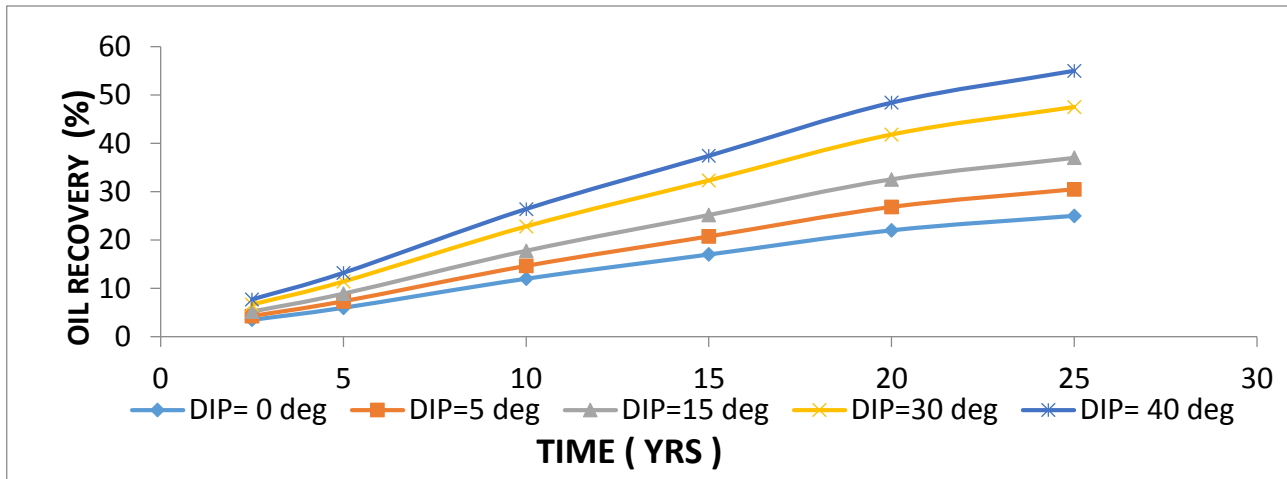


Figure 2: Oil Recoveries as a Function of Reservoir Dip

The heterogeneity index of the reservoir captures the degree of change of reservoir permeability with space from different locations in the reservoir and is inversely proportional to oil recovery as shown in Figure 3. Higher degree of heterogeneity results in lower incremental recovery. Reservoir heterogeneity index of 74.4 gives an incremental recovery of 19.14% while the heterogeneity index of zero gives an incremental recovery of 33% showing a 14% improvement.

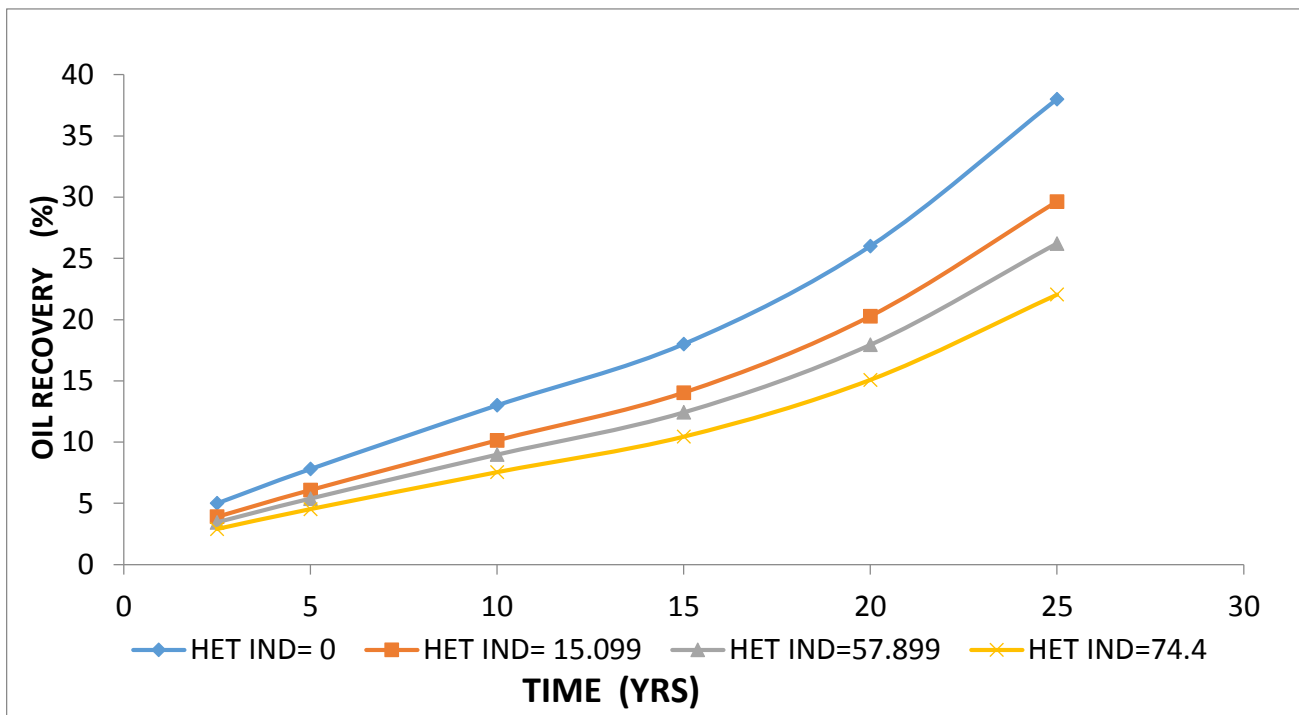


Figure 3: Oil Recoveries as a Function of Reservoir Heterogeneity

Mobility ratio of carbon dioxide to oil is an important parameter that needs to be large enough to ensure incremental recovery. The mobility ratio of the displacing fluid needs to be much higher than the displaced fluid. Hence, from Figure 4, it is observed that at a mobility ratio of 23.11, incremental oil

recovery was 31% while at the mobility ratio of 3.2, incremental oil recovery was 14.23%.

Considering fluid gravities, CO<sub>2</sub> can evaporate the condensable portion of the reservoir fluid which makes it better than methane injection which targets just the intermediate

components. Lighter oils with large API gravities are favored by CO<sub>2</sub> flooding as seen in Figure 5. API gravity of 20 will yield an incremental oil recovery of 19.20% while 36.4 API gravity will produce an incremental oil recovery of 33.6%. Volume of CO<sub>2</sub> injected depends on the availability of the gas. Injected rate is monitored by increasing the volume for different simulation runs. When 20,000 SM<sup>3</sup>/D is used, the incremental oil recovery is 12.5% and when the injected rate

of 180,000 SM<sup>3</sup>/D was applied the incremental oil recovery was 26.5% as illustrated in Figure 6.

In Fig. 7, the pore volume influences the oil recovery from the carbon dioxide flooding operation. When CO<sub>2</sub> is injected at 2 PV, the incremental oil recovery is 36% while at a pore volume of 0.4 PV, the incremental oil recovery was 20.88%

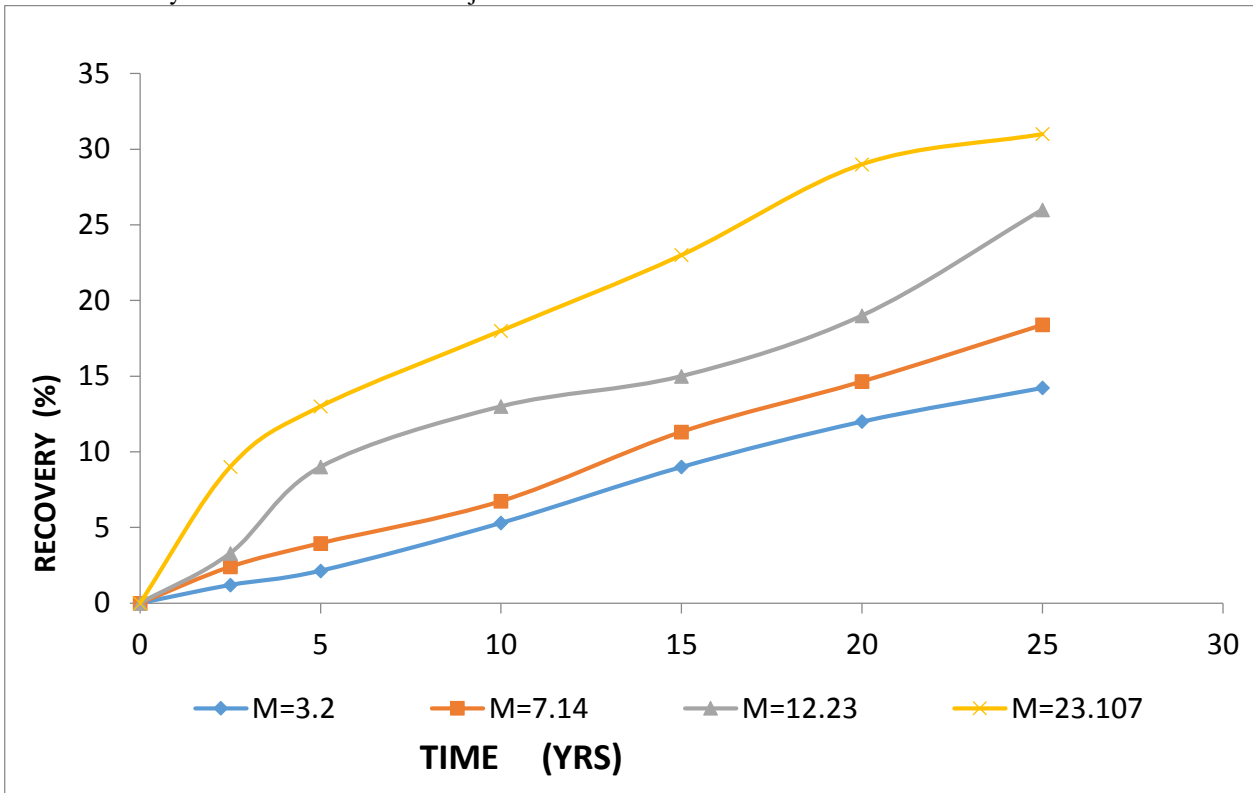


Figure 4 Oil Recoveries as a Function of CO<sub>2</sub> Mobility Ratio

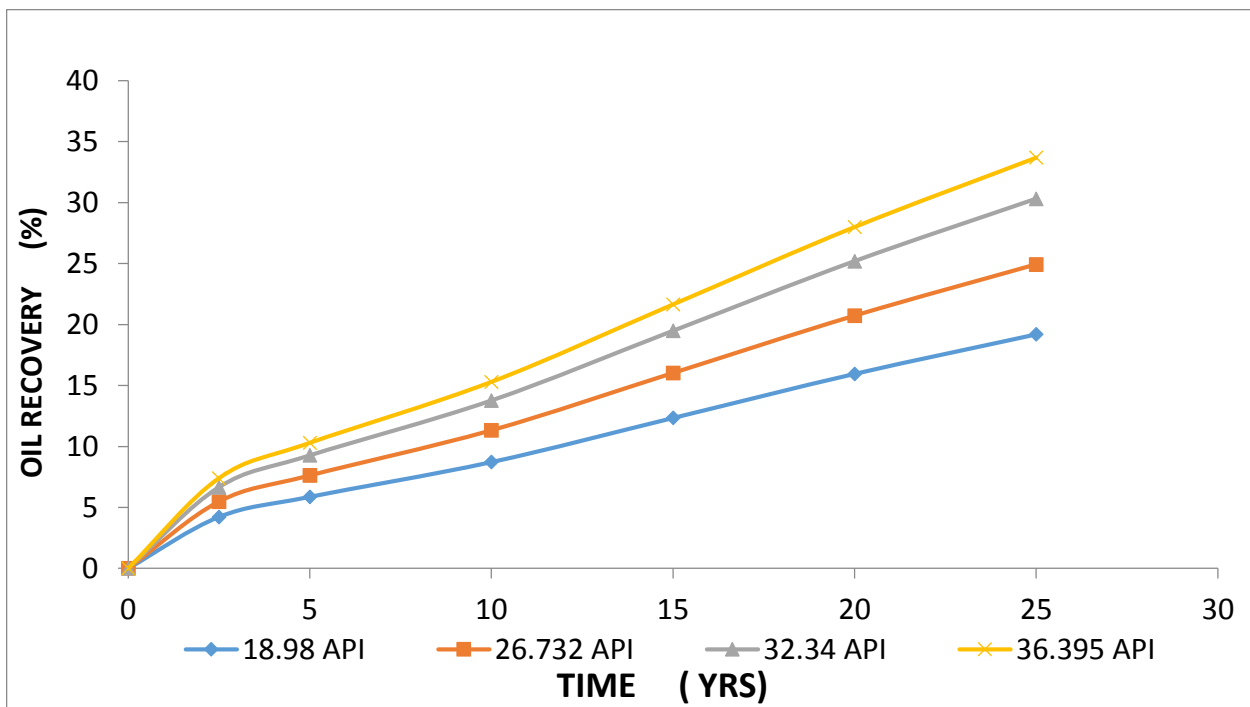


Figure 5: Oil Recoveries as a Function of Fluid Gravity

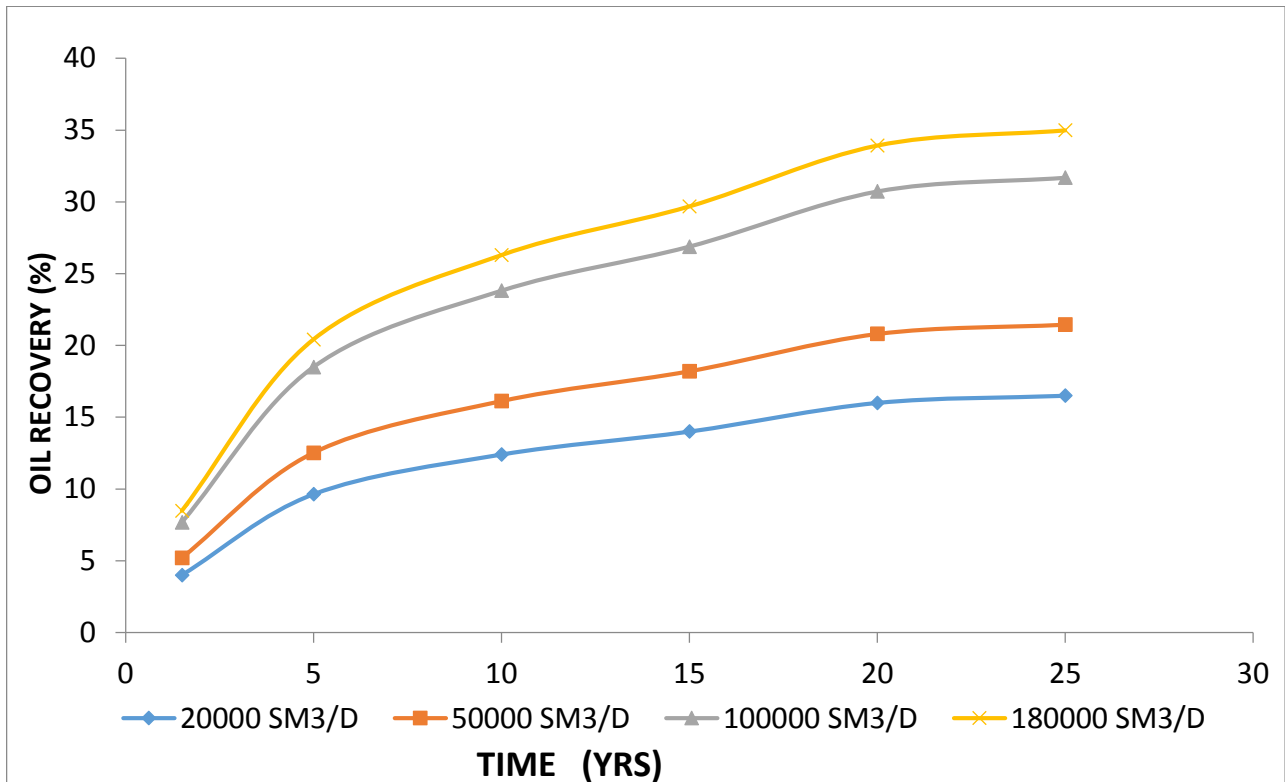


Figure 6: Oil Recoveries as a Function of CO<sub>2</sub> Injection Rate

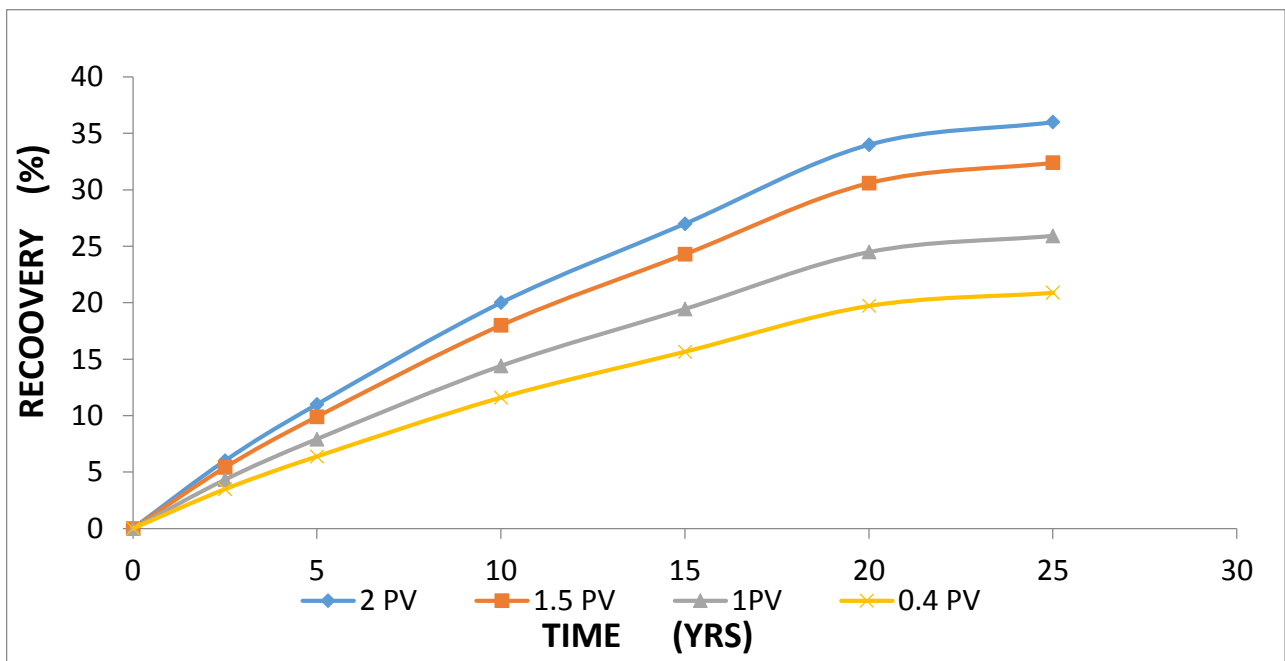


Figure 7 Oil Recoveries as a Function of CO<sub>2</sub> Volume Injected

## X. CONCLUSION

The results have shown that reservoir heterogeneity and dip, CO<sub>2</sub> to oil mobility ratio, injection rate, volume of CO<sub>2</sub> injected, reservoir fluid nature and injection well configurations are important parameters that affect the performance of CO<sub>2</sub> EOR projects. A *priori-knowledge* of extra recovery expected to be obtained if CO<sub>2</sub> EOR is embarked on is no doubt a prudent approach and promotes best engineering practices. The nature of the fluids has a direct implication on the retention time of the CO<sub>2</sub> to oil miscibility;

hence, the reservoir fluids with higher molecular ends will tend to have higher C<sub>5+</sub> components which translate to a higher MMP and thus a greater time to attain miscibility.

## NOMENCLATURE

- API = American Petroleum Institute
- B<sub>g</sub> = Gas formation volume factor (RM<sup>3</sup> / SM<sup>3</sup>)
- B<sub>t</sub> = Two phase formation volume factor, (RM<sup>3</sup> / SM<sup>3</sup>)
- CO<sub>2</sub> = Carbon Dioxide

EOR = Enhanced Oil Recovery  
 EOS = Equation of State  
 FPV = Fractional Pore Volume, ratio  
 HCPV = Hydrocarbon Pore Volume, RM<sup>3</sup>  
 $K_{r_{CO_2}}$  = Relative permeability of rock to CO<sub>2</sub>  
 $K_{rowg}$  = Relative permeability of rock to oil in the presence of water and gas  
 M = Mobility Ratio of CO<sub>2</sub> to Oil  
 MMP = Minimum Miscibility Pressure  
 MW = Molecular Weight  
 $P_{fi}$  = Formation Pressure  
 PR = Peng Robinson EOS  
 PVT = Pressure-Volume-Temperature.  
 RM<sup>3</sup> = Reservoir Cubic Meter  
 RSPV = Reservoir Pore Volume, RM<sup>3</sup>  
 Rsi = Solution Gas oil Ratio, ( SM<sup>3</sup>/ SM<sup>3</sup>)  
 $R_s$  = Solution gas ratio ( SM<sup>3</sup>/ SM<sup>3</sup>)  
 $R_p$  = Produced gas oil ratio (SM<sup>3</sup>/ SM<sup>3</sup>)  
 $Q_{inj}$  = CO<sub>2</sub> injection Rate  
 SM<sup>3</sup> = Standard Cubic Meter  
 SRK = Soave-Redlich-Kwong EOS  
 $T_g$  = Temperature gradient °F  
 $\mu_o$  = Oil Viscosity  
 WAG = Water Alternating Gas

## ACKNOWLEDGEMENT

The Authors wish to thank the staff of the Department of Petroleum Engineering and the Office of Petroleum Engineering Shell Chair, University of Ibadan for their support in the course of this project. Special thanks to Schlumberger, for the learning Center at the University of Ibadan for the use of Eclipse for this project.

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