CO_2-ASSISTED GRAVITY DRAINAGE EOR: NUMERICAL SIMULATION AND SCALING MODELS STUDY

A thesis

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By

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7 SCALING AND SENSITIVITY ANALYSIS

The results obtained through reservoir simulations in the CO_2-assisted gravity drainage EOR method can be applicable to the field reservoir through the scaling approach. The multiphase parameters responsible for the gravity-drainage oil recovery if analyzed by this approach, it is possible to predict the EOR performance at the field scale. Such scaling through the dimensional analysis is investigated in this section with regards to its applicability to CO_2-assisted gravity drainage EOR process.

Identification of the important multiphase parameters interacting during operation of the CO_2-assisted gravity drainage EOR process is carried out through the risk analysis using PALISADE’s @RISK software. Their interplay is then studied in both the immiscible and miscible process through two techniques. In first, a correlation representing the combination dimensionless group is developed based on the profile of oil recovery changes with respect to the traditional dimensionless numbers viz. capillary, bond and gravity number, and viscosity ratio. In second technique, uncertainty assessment method is used to investigate relationship between the scaling groups and their effect on the overall performance of immiscible CO_2-assisted gravity drainage EOR process.

7.1 Identification of Operational Multiphase Parameters Controlling the CO_2-Assisted Gravity Drainage Oil Recovery

Based on the gravity drainage field studies, the key multiphase parameters operational in the CO_2-assisted gravity drainage EOR process are identified and are presented in **Table 2-6**. Their relative dominance during the progress of CO_2-assisted gravity drainage EOR process is investigated in this study using the PALISADE’s @RISK software. Monte Carlo simulations are carried over the ranges of available variable parameters (**Table 7-1**) through 5000 iterations. Deterministic parameters (e.g.: length, depth etc.) do not change for the process under consideration for a given reservoir settings. Probabilistic parameters are defined in two types of probability distribution function (PDF), i.e. normal and triangular. Total fluid velocity, u_T (ft/d), viscosity, μ (cP) and the absolute permeability, k (mD) are assumed as normal PDFs represented by its mean and standard deviation. Other parameters are defined as triangular PDFs with its minimum, most likely, and maximum value (**Table 7-1**). Values of the parameters are based on the gas injection gravity drainage field case studies as represented in **Table 2-6** of Chapter-2.

Table 7-1: Ranges of the parameters (CO_2-GAGD EOR process) values used in the risk analysis

Parameter	Deterministic	Probabilistic				
		Mean	Std Dev	Minimum	Most Likely	Maximum
H (ft)	1500					
L (ft)	30000					
k_z (mD)	1200			100	1200	3400
λ_{ro}		0.28226	0.08318			
$\Delta\rho$ (lb/ft^3)	52.8872			10	52.8872	120
g (ft/s^2)	32.174					
u_T (ft/D)		0.00647	0.00179			
k_{rw}				0.18	0.3	0.48
k_{ro}				0.35	0.7	0.85
k_{rg}				0.1	0.3	0.4
μ_o (cP)				0.19	0.5	3.7
μ_w (cP)				0.25	0.3647	0.58
μ_{CO2} (cP)				0.0182	0.056	0.11

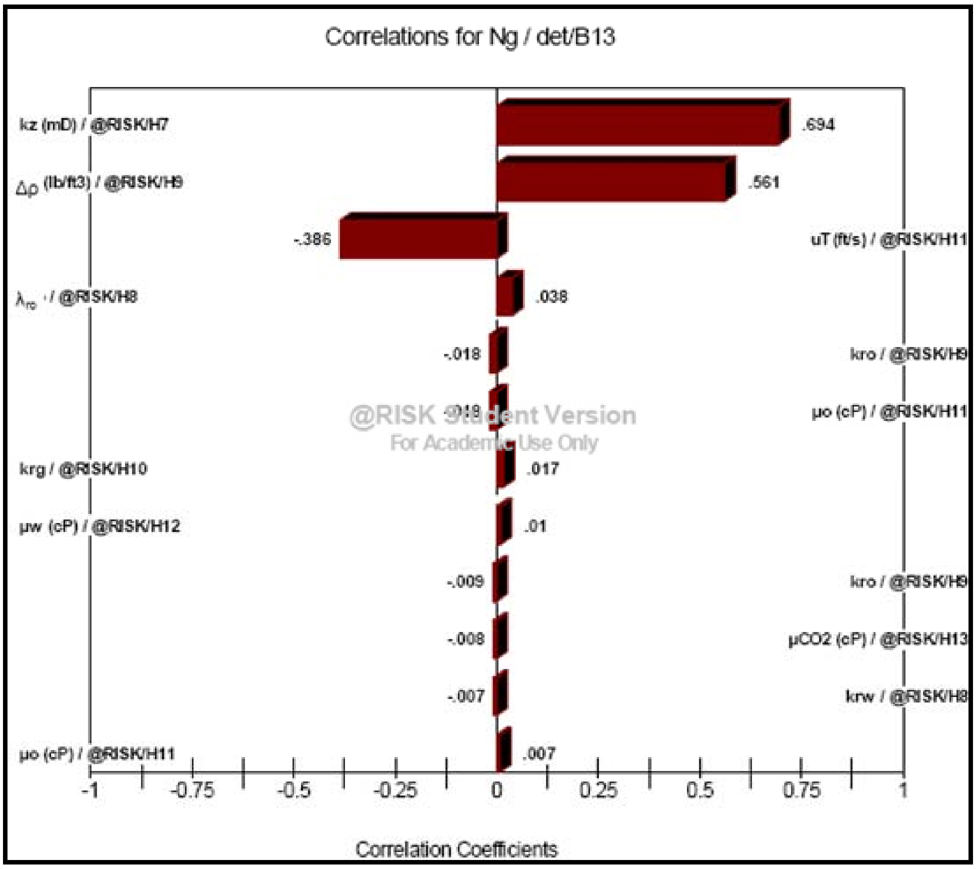

Figure 7-1: Tornado diagram depicting the relative dominance of multiphase parameters operational in the CO_2-GAGD EOR process

The Monte Carlo simulations using the @RISK software are first carried out cumulatively on all the groups. Risk analysis results are presented in **Figure 7-1** in the form of Tornado diagram. Analysis shows that vertical permeability is the most dominant parameter that will have largest impact the CO_2-assited gravity drainage EOR process, which is followed by the density difference between the injected CO_2 and reservoir oil. It is so in GAGD-EOR process because the reservoir oil is displaced downward towards the horizontal producers placed at the bottom of the pay-zone. Good vertical communication between layers is one of the necessary conditions for the success of a gravity drainage oil recovery process. Also larger the density differences between the injected fluid and reservoir oil, higher will be the gravity segregation effects and better gravity-drainage oil displacement. Total superficial velocity (u_T) of the fluids and the end point oil mobility (λ_{ro}) follow k_v and $\Delta\rho$. Absolute permeability and the oil and gas viscosity contributes the mobility ratio. Total superficial velocity contributes the viscous forces which in turn compete with the gravity forces, which is also one of the important parameters while assessing the overall gravity drainage recovery performance. Relative permeability to water and oil, followed by the water viscosity, were shown to be next critical parameters for the M_{wo}. For gas-oil mobility ratio, gas viscosity is shown to be the next critical parameter followed by the relative permeability of gas and oil.

7.2 Scaled Model Studies: 50 ^oAPI Reservoir

Risk analysis in the previous section identified the vertical permeability, the difference of density between the injection gas CO_2 and reservoir oil, the total superficial velocity; and the oil and gas viscosity as operational parameters that significantly impact CO_2-assisted gravity drainage EOR process. Gravity and, another microscopic property, the interfacial tension (IFT) contributing the capillary forces, play an important role in the ultimate oil recovery.

Reservoir simulation studies presented in Chapter-6 showed that the oil recovery curve after the gas floodfront reached the producing wells tend to flatten out to reduce the oil recovery rate. This is mainly attributed to capillary forces which oppose the release of the oil trapped inside the small pores to the bulk flow. Capillary retention thus opposes the gravity forces that have strong influence on the oil recovery especially in the CO_2-assisted gravity drainage EOR process.

Interplay of all of these dominant parameters and forces can be factored into the equations that facilitate the scaling of reservoir simulation results to the field application. These are represented by the dimensionless numbers derived from the combination of dimensionless groups obtained through dimensional analysis. Literature review presented in section 2.4 suggests that the most notable and applicable numbers/groups to gravity drainage EOR process are the Capillary number (N_C), Gravity number (N_G) and Bond number (N_B) (see **Table 2-7**). Capillary number (N_C) represent the ratio of viscous to capillary forces while the Gravity number represent the ratio of gravity to viscous forces (Grattoni *et al.*, 2001). Interaction of the gravity and capillary forces is represented by the Bond number (N_B) (Grattoni *et al.*, 2001).

Table 7-2: Dimensionless numbers used in evaluation of CO_2-asssited gravity drainage EOR process

Eq. No.	Number	Correlation	Reference
7.1	Capillary Number	$N_C = \frac{V.\mu}{\sigma}$	Grattoni *et al.*(2001)
7.2	Bond Number	$N_B = \frac{\Delta\rho.g.l^2}{\sigma}$	Edwards *et al.* (1998)
7.3	Gravity Number	$N_G = \frac{\Delta\rho.g.k}{\Delta\mu.u}$	Grattoni *et al.*, (2001)
7.4	New Group of Kulkarni	$N_K = N_G + \left(\frac{\rho_G}{\rho_O}\left(N_C + N_B\right)\right)$	Kulkarni (2005)
7.5	New Group of Rostami *et al.* (2009)	$N_{rostami} = \frac{N_B\left(\mu_r\right)^A}{\left(N_C\right)^B}$	Rostami *et al.*, (2009)

In this section, these dimensionless numbers are studied to investigate their effect on the CO_2-assisted gravity drainage EOR methods with respect to oil recovery (% OOIP). Reservoir response to dimensionless numbers helped to identify the inter-relation between the interacting mechanistic operational parameters. Based on these inter-relations, a new correlation is suggested. Using this correlation, the results of the reservoir simulation studies in both the homogeneous (1200 mD; k_v/k_h=1.0) and heterogeneous (120 mD; k_v/k_h=0.1 and 1.2 mD; k_v/k_h=0.001) permeable media are then matched with field data to validate their field applicability.

Dimensionless numbers (using equations given in **Table 7-2**) are calculated (**Table 7-3**) using the data from the reservoir simulation studies in this study and the gravity drainage field projects (**Table 2-6**). Moreover, additional gravity drainage field data from the Oseberg Field, Norway, which is a reservoir outside USA, is also included in this study. Missing parametric data such as interfacial tension ($\sigma_{gas\text{-}oil}$) is calculated from the single phase and two phase flash conducted using CMG's fluid properties program WinProp. Variation in dimensionless numbers N_C, N_G and N_B are presented versus the oil recovery obtained in the respective reservoir simulation results (at $1PV_{CO2inj}$) and the field projects. **Table 7-3** presents those calculated numbers including the new dimensionless number ($_{NJadhawar\ and\ Sarma}$) proposed in this study.

For extending the application of dimensionless groups *viz.* N_C, N_G and N_B to the miscible CO_2-assisted gravity drainage EOR process, following three assumptions have been made. These do not modify multiphase parameters and the physical meaning of the miscible process. Therefore they facilitate an opportunity to compare the results in both the immiscible and miscible CO_2-assisted gravity drainage EOR processes. These assumptions are:

1. Density and viscosity difference between CO_2 and the injection gas is replaced by their average as there is no contrast in their values in the miscible zone.
2. Interfacial tension (σ) between CO_2 and the reservoir oil is 0.001 at the time of miscibility achievement.
3. The length term in Bond number (N_B) is replaced by the square root of the ratio of absolute permeability and porosity

Table 7-3: Key dimensionless numbers calculated using results of this reservoir simulation study in the CO_2-GAGD EOR process and the gravity drainage field data

No.	Study	Reservoir sim/Field tile	N_C	N_B	N_G	$N_{Kulkarni}$	$N_{Rostami}$	$N_{Jadhawar\ \&\ Sarma}$	Recovery (% OOIP)
1	Immiscible Field Projects	West Hackberry	1.60E-08	2.38E-06	7.18E-01	7.18E-01	3.49E-03	2.61E+00	63.00
2		Weeks Island	3.36E-08	1.21E-05	2.92E+01	2.92E+01	3.21E-02	1.40E+02	72.00
3		Intisar D	5.36E-06	5.45E-03	1.00E+01	1.00E+01	5.49E-01	2.07E+01	67.50
4		**OSEBERG**	4.54E-06	6.93E-03	7.45E+01	7.45E+01	7.80E-01	1.62E+02	71.00
5	Immiscible this Study	CO2-GAGD-SEC-I	1.35E-10	2.25E-05	5.48E+03	1.00E+01	6.99E-01	1.52E+05	83.62
6		CO2-GAGD-SEC-II	3.05E-10	2.25E-05	2.43E+03	2.43E+03	4.65E-01	5.74E+04	83.50
7		CO2-GAGD-SEC-III	5.07E-10	2.25E-05	1.46E+03	1.46E+03	3.61E-01	3.11E+04	83.32
8		CO2-GAGD-SEC-IV	6.76E-10	2.25E-05	1.10E+03	1.10E+03	3.12E-01	2.21E+04	83.15
9	Miscible Field Projects	Wolfcamp Reef	1.62E-05	3.01E-03	1.62E+00	1.62E+00	2.28E-01	4.24E+00	74.80
10		West Pem Nisku	1.83E-06	2.88E-02	2.85E+03	2.85E+03	7.84E+00	5.12E+03	84.00
11		Wizard Lake D3A	3.24E-06	5.77E-02	7.12E+03	7.12E+03	9.20E+00	3.47E+03	86.00
12	Miscible this study	CO2-GAGD-SEC-I	2.27E-07	2.86E-02	1.26E+04	1.26E+04	3.25E+01	1.35E+05	88.52
13		CO2-GAGD-SEC-II	5.10E-07	2.86E-02	5.60E+03	5.60E+03	2.17E+01	5.12E+04	87.20
14		CO2-GAGD-SEC-III	8.46E-07	2.86E-02	3.38E+03	3.38E+03	1.68E+01	2.79E+04	86.90
15		CO2-GAGD-SEC-IV	1.12E-06	2.86E-02	2.56E+03	2.56E+03	1.47E+01	2.00E+04	86.30
16		NB-1 misc (1200 mD)	1.12E-06	2.86E-02	2.56E+03	2.56E+03	1.47E+01	2.00E+04	84.81
17		NB-1 misc (1200 mD)	1.12E-06	2.86E-02	2.56E+03	2.56E+03	1.47E+01	2.00E+04	84.20
18		NB-2 misc, 120mD	1.12E-06	2.86E-03	2.56E+02	2.56E+02	1.47E+00	2.00E+03	83.00
19		NB-3 misc, 1.2mD	1.12E-06	2.86E-05	2.56E+00	2.56E+00	1.47E-02	2.00E+01	77.00

7.2.1 Capillary Number (N_C)

Four combinations of injection and production rates were used to study the oil recovery process performance through reservoir simulations in the immiscible and miscible CO_2 assisted gravity drainage EOR process (section 6.1 in Chapter 6). This wide range of the rates provided larger spectrum of the gravity drainage velocity for use in the capillary number study. Its variation over different injection rates in both the immiscible and miscible process with the oil recovery (% OOIP) is shown in **Figure 7-2** and **Figure 7-3** respectively.

In both the immiscible and miscible process, oil recovery decreased with the increasing injection rates, so the capillary number (N_C) representing the ratio of the viscous and capillary force. This means that the increase in the viscous force (derived from the gravity drainage velocity) tends to show decreasing oil recovery pattern.

Green hollow diamonds in **Figure 7-2** show the respective capillary numbers in the immiscible process. The porous medium in the immiscible reservoir simulations is having absolute permeability of 1200 mD, leading to a constant Bond number (N_B) of 2.25E-05 (discussed in section 7.2.3). Miscible process capillary numbers are indicated by the red hollow diamonds in the **Figure 7-2**. At a constant N_B (2.86E-02), the increasing N_C values in the respective miscible process indicated the similar decreasing profile of oil recovery. Therefore, capillary number variation further implies that oil recovery in both the immiscible and miscible CO_2-GAGD EOR process is inversely proportional to the Capillary number (N_C). It is important to note here that the oil recovery decrease in the reservoir simulation results from this study was very less with 1 to 2% OOIP.

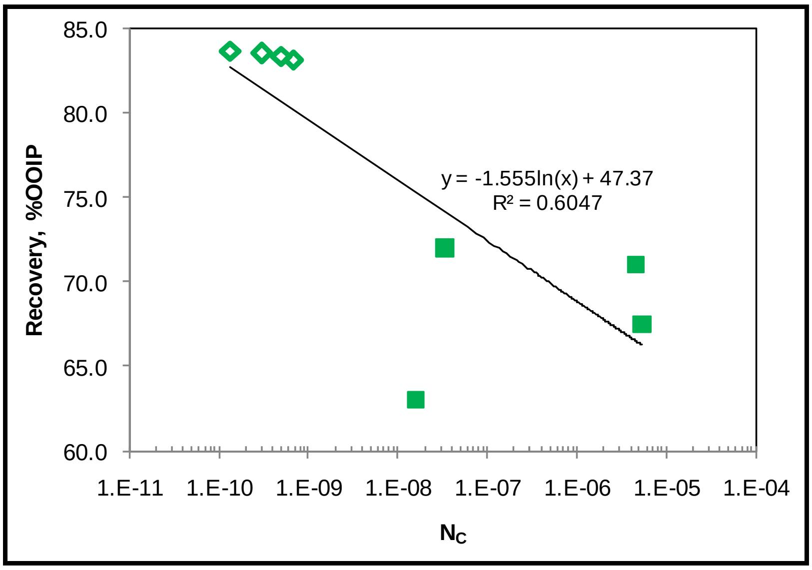

Figure 7-2: Effect of Capillary number on oil recovery in *immiscible* CO_2-GAGD EOR process. Green squares: N_C from field projects. Green hollow diamonds: N_C from this study

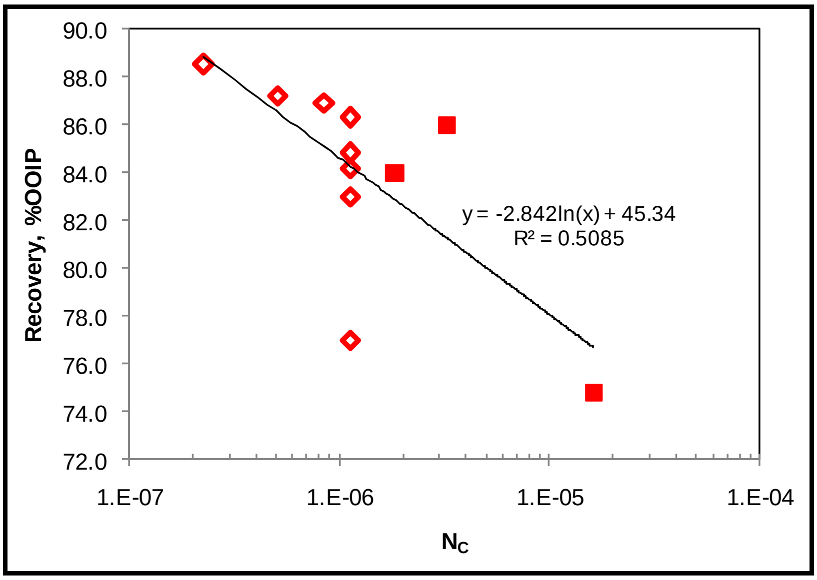

Figure 7-3: Effect of Capillary number on oil recovery in *miscible* CO_2-GAGD EOR process. Red Squares: N_C from field projects. Red Hollow diamonds: N_C from this study

Capillary number studies in the miscible process yielded another important observation when vertical permeability is changed from 1200 mD (Case-I to Case-IV injection rate combinations) to 120 mD and 1.2 mD. Respective Bond numbers depicted by red hollow diamonds placed in the vertical array from bottom to top are 2.856E-05, 2.856E-03, 2.856E-02 and 2.856E-02 (**Figure 7-3**). At a constant N_C, oil recovery found to increase with the increasing permeability, so the bond number (N_B).

Field project data from the West hackberry, Weeks Island, Intisar-D and Oseberg field for the immiscible process evaluation and Wolfcamp Reef, Westpem Nisku and Wizard lake field for the miscible process are used in evaluating the Capillary number variation with respect the oil recovery. In both the immiscible and miscible process, oil recovery found to diminish with the increasing N_C.

Moreover, these results indicate that there is a correlation between the N_C and N_B with regards to the oil recovery in the respective oil recovery process. This is investigated in the following sections. Furthermore, N_C is a function of viscous and capillary force. Therefore, it is insufficient to describe the effect of gravity forces on its own.

7.2.2 Bond Number (N_B)

Immiscible process oil recovery variation with Bond number (N_B) is as shown in **Figure 7-4**. Four closely spaced oil recovery profile (diamonds) indicate that the increase in the capillary number values from 1.35E-10 to 6.76E-10 (see **Table 7-2**) at a constant Bond number (NB) of 2.25E-05 leads to the reduction in oil recovery from 83.62% to 83.15%. Moreover, the field data show that the oil recovery improves with the increase in Bond number (N_B).

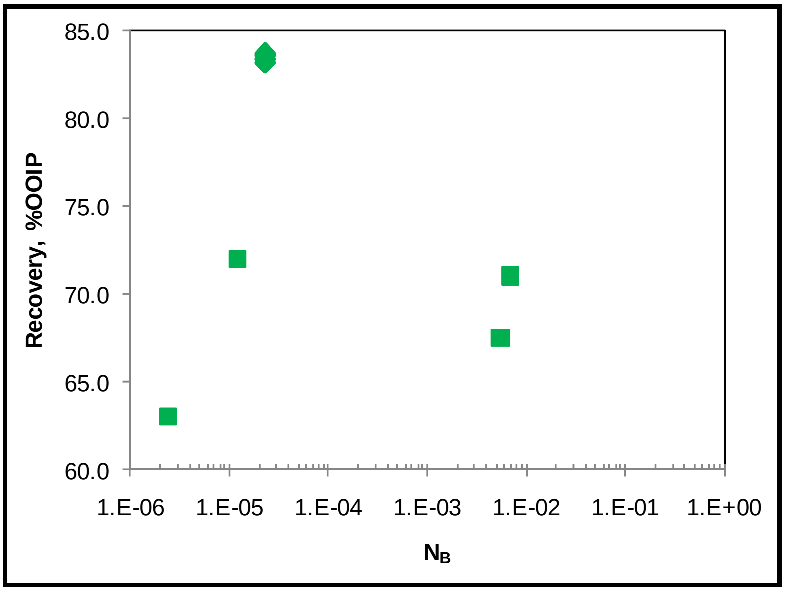

Figure 7-4: Effect of N_B on oil recovery in the immiscible CO_2-GAGD EOR process. Green Squares: N_B - field projects. Green Hollow diamonds: N_B - this study

In miscible process, oil recovery decreases from 88.52% to 86.3% with the increasing injection rates, so the capillary number values from Case-I to Case-IV at a constant Bond number of 2.86E-02. These are denoted by the red hollow diamonds in vertical array in **Figure 7-5**. While remaining red hollow diamonds are the oil recoveries in three permeability medium of 1200 mD, 120mD and 1.2mD at the constant capillary number of 1.12E-06 (Case-IV injection rate). Results show that oil recovery improves with increase in the respective Bond numbers (N_B). Bond number profile from the field projects, shown by the red squares **Figure 7-5**, also yield similar observations.

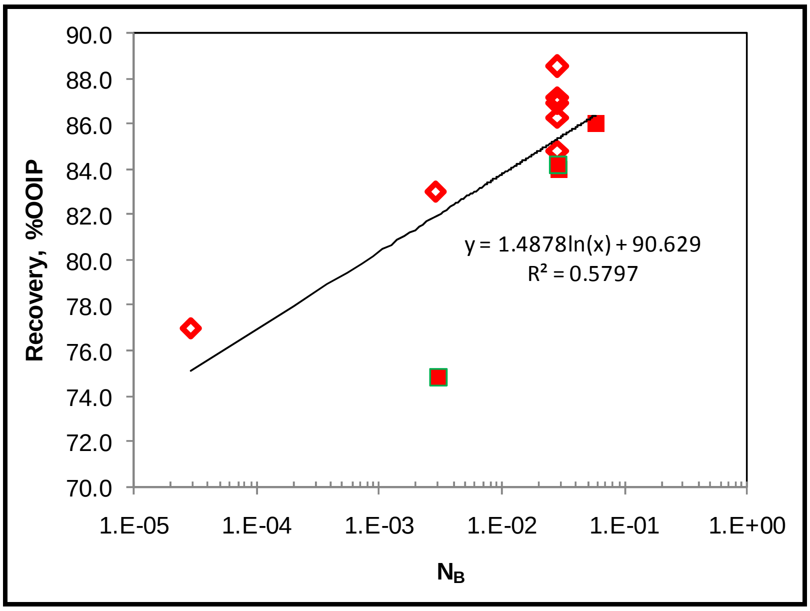

Figure 7-5: Effect of N_B on oil recovery in the *miscible* CO_2-GAGD EOR process. Red Squares: N_B - field projects. Red Hollow diamonds: N_B - this study

Profile of the Bond numbers and the related capillary numbers for the respective oil recovery indicated that the oil recovery in CO_2-assisted gravity EOR process is directly proportional to the bond number and inversely proportional to the capillary number. Moreover, the data plotted in **Figure 7-4** and **Figure 7-5** did not yield the satisfactory match indicating that bond number alone cannot capture all the process operational multiphase parameters. There could be other important parameters needs to be considered while assessing the CO_2-assisted gravity EOR process performance through the dimensionless numbers.

7.2.3 Gravity Number (N_G)

Gravity number depends on the gravity, oil and gas density, absolute permeability of the porous medium, oil and gas viscosity and gravity drainage velocity. Thus gravity number (N_G) mainly represents the ratio of the gravity and viscous forces.

Gravity number variation corresponding to the oil recovery in immiscible process is as shown in **Figure 7-6**. Hollow green diamonds shown in figure are the gravity numbers at the respective capillary numbers from the highest to the lowest injection rates (Case-IV to Case-I) at the constant N_B of 2.25E-05. The linearly increasing trend of oil recovery with the gravity number indicates the direct proportional relation of gravity number with the oil recovery (% OOIP). Moreover, the oil recovery in field projects exhibited similar trend with respect to the field gravity numbers (N_G) and the related field capillary numbers (N_C). Evaluation of the field projects shows that the increase in Bond numbers (N_B) from the lowest West Hackberry field (2.38E-06) to highest Oseberg field (6.93E-03) improved the oil recovery with the corresponding increase of gravity number from 7.81E-01 to 7.45E+01.

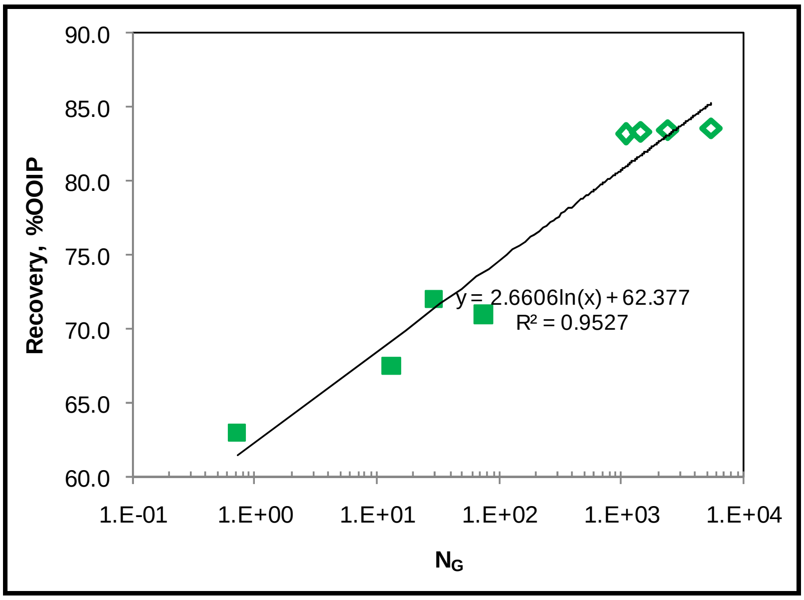

Figure 7-6: Effect of Gravity number on oil recovery in *immiscible* CO_2-GAGD EOR process. Green squares: N_G from field projects. Green hollow diamonds: N_G from this study

Miscible process gravity number performance with the oil recovery is presented in **Figure 7-7**. Four hollow red diamonds shown at the top-right corner are the increasing gravity numbers at the respective capillary numbers from the highest to the lowest injection rates (Case-IV to Case-I) at the constant N_B of 2.86E-02. The linear increasing oil recovery trend with the gravity number indicates that there is a direct proportional relationship between the gravity number (N_B) and the corresponding oil recovery (% OOIP). Whereas the remaining three red hollow diamonds indicates the increasing oil recovery trend with the respective gravity numbers at the corresponding increasing Bond numbers (NB) from 2.86E-05 (77% OOIP) to 2.86E-02 (84.2% OOIP) and the constant capillary numbers (NC) of 1.12E-06.

Moreover, the oil recovery in field projects exhibited similar trend with respect to the field gravity numbers (N_G) and the related reducing capillary numbers (N_C). Evaluation of the field projects shows that the increase in Bond numbers (N_B) from the lowest Wolfcamp Reef field (3.01E-03) to highest Wizard lake D3A field (5.77E-02) improved the oil recovery (74.80 to 86%) with the corresponding rise in gravity number from 1.62E+00 to 7.12E+03.

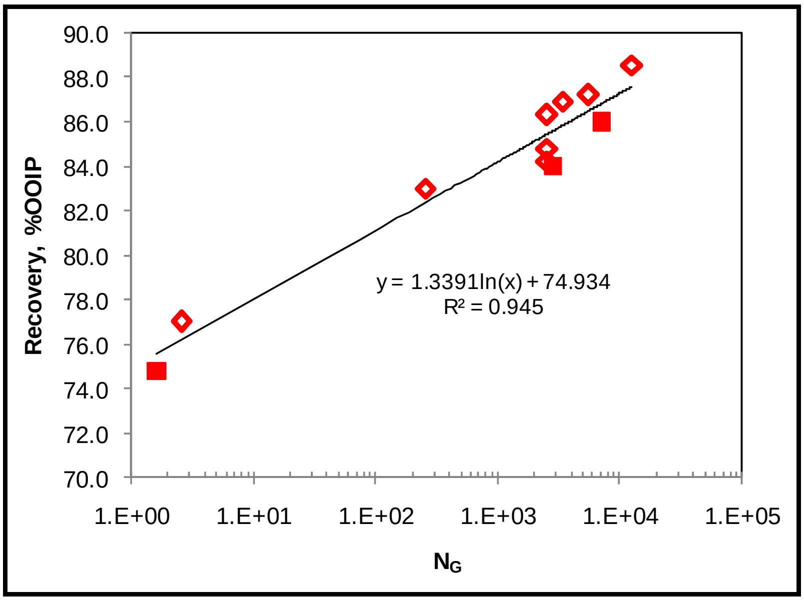

Figure 7-7: Effect of Gravity number on oil recovery in *miscible* CO_2-GAGD EOR process. Red Squares: N_G from Field projects. Red Hollow diamonds: N_G from this study

As mentioned previously that gravity number represents the interaction of the gravity and viscous forces. It does not capture the effect of the capillary forces. Although the gravity number data provided reasonably accurate and close correlation, there could be other important multiphase parameters that must be considered in this evaluation. This analysis further indicates that the gravity number alone cannot capture the effect of all the process operational multiphase parameters. What are those other mechanistic parameters and how they affect the gravity drainage oil recovery process are discussed in the following section.

7.2.4 Combination Models: Evaluation of the Existing Numbers

Literature review suggest that the most applicable combination scaling groups to the gravity drainage oil recovery process are presented by Grattoni *et al.* (2001), Kulkarni (2005) and Rostami *et al.* (2009). Scaled model of Grattoni (2001) represented the combination of the capillary and bond number, which excluded the gravity number. Kulkarni (2005) eliminated this limitation with the inclusion of the gravity number term and thereby factoring the density ratio in the combination model. Rostami *et al.* (2009) presented a model with the bond and capillary number thereby the inclusion of the viscosity ratio term and neglecting the gravity number term. This section evaluates the performance of CO_2-assisted gravity drainage EOR process using the combination models presented by Kulkarni (2005) and Rostami *et al.* (2009).

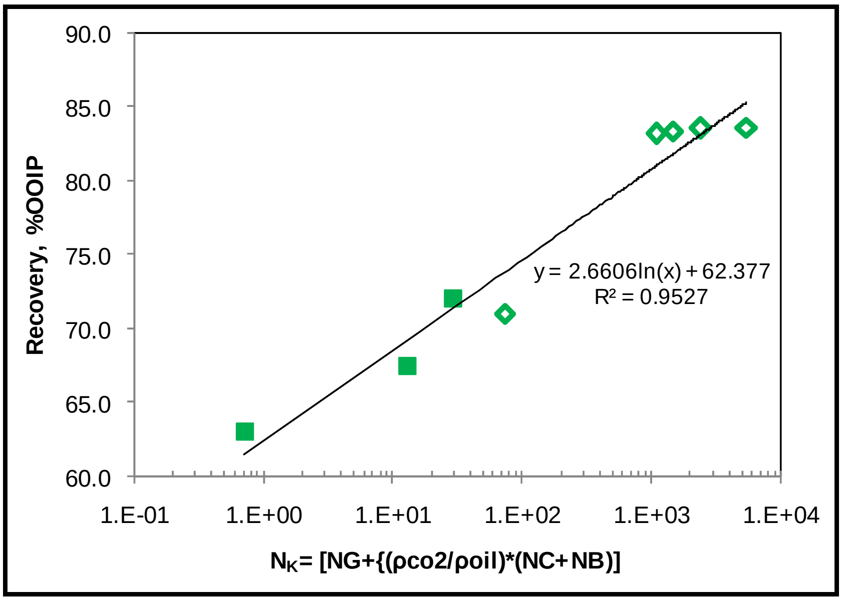

Figure 7-8: Effect of the combination model of kulkarni (2005) on oil recovery in the *immiscible* CO_2-GAGD EOR process. Green squares: N_K - field projects. Green hollow diamonds: N_K - this study

Kulkarni (2005) factored the ratio of the injection gas density to the reservoir oil density in his combination model in an attempt to encompass the multiphase parameters operational in the GAGD-EOR process. The equation 7.4 given in **Table 7-2** is used in evaluating its applicability to the results conducted in this study. Oil recovery (% OOIP) vs. kulkarni number (N_K) plot is presented in the **Figure 7-8** and **Figure 7-9** for the immiscible and miscible CO_2-assisted gravity drainage EOR process respectively. Both of these processes yield good agreement between the results of this study in homogeneous (1200 mD; k_v/k_h=1.0) and heterogeneous (120 mD; k_v/k_h=0.1 and 1.2 mD; k_v/k_h=0.001) permeable media as well as in the field projects.

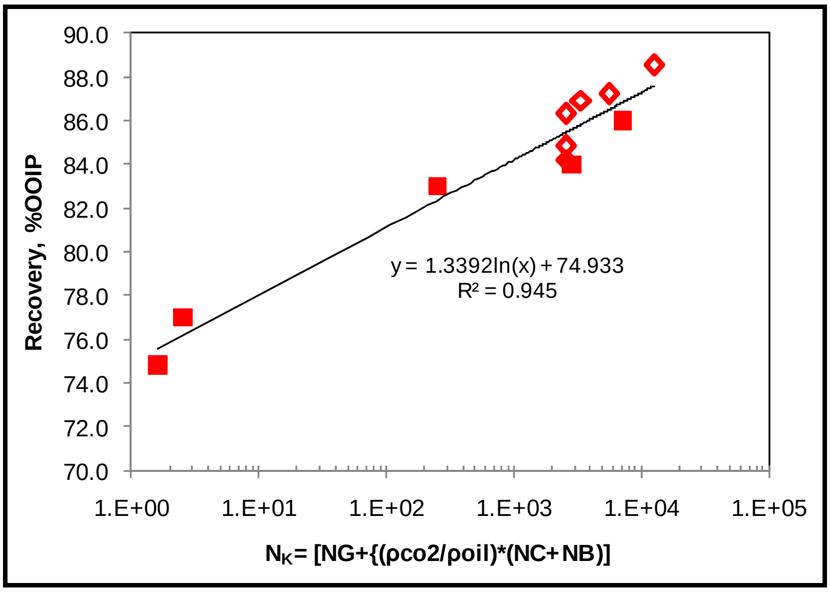

Figure 7-9: Effect of the combination model of kulkarni (2005) on oil recovery in the *miscible* CO_2-GAGD EOR process. Red squares: N_K - field projects. Red hollow diamonds: N_K - this study

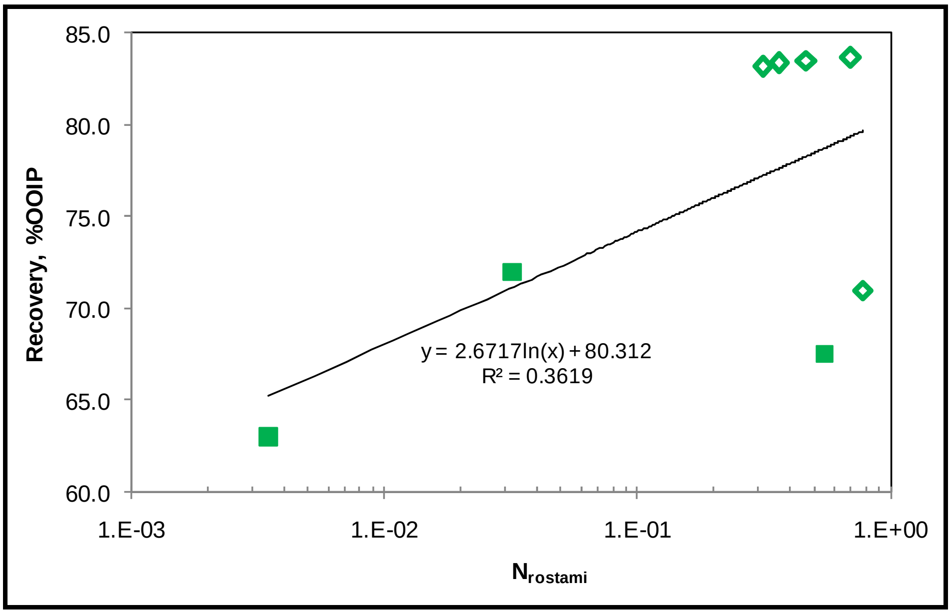

Figure 7-10: Effect of combined model of Rostami (2009) on oil recovery in *immiscible* CO_2-GAGD EOR process. Green squares: $N_{Rostami}$ - field projects. Green hollow diamonds: $N_{Rostami}$ - this study

Rostami *et al.* (2009) suggested a new group (eq 7.5 in **Table 7-2**) based on their experimental data thereby factoring capillary number to the denominator. His correlation is also used in this study to investigate its application using the results of the reservoir simulations and the data from the field projects. Oil recovery profile with respect to dimensionless number by Rostami *et al.* (2009) in both the immiscible and miscible process are as shown in **Figure 7-10** and **Figure 7-11**. A scattered distribution of the dimensionless combination number of Rostami *et al.* (2009) and the respective oil recoveries in the reservoir simulation and the field projects is obtained in this evaluation. This suggests that there could be other parameters that need to be considered while evaluating the CO_2-assisted gravity drainage EOR process.

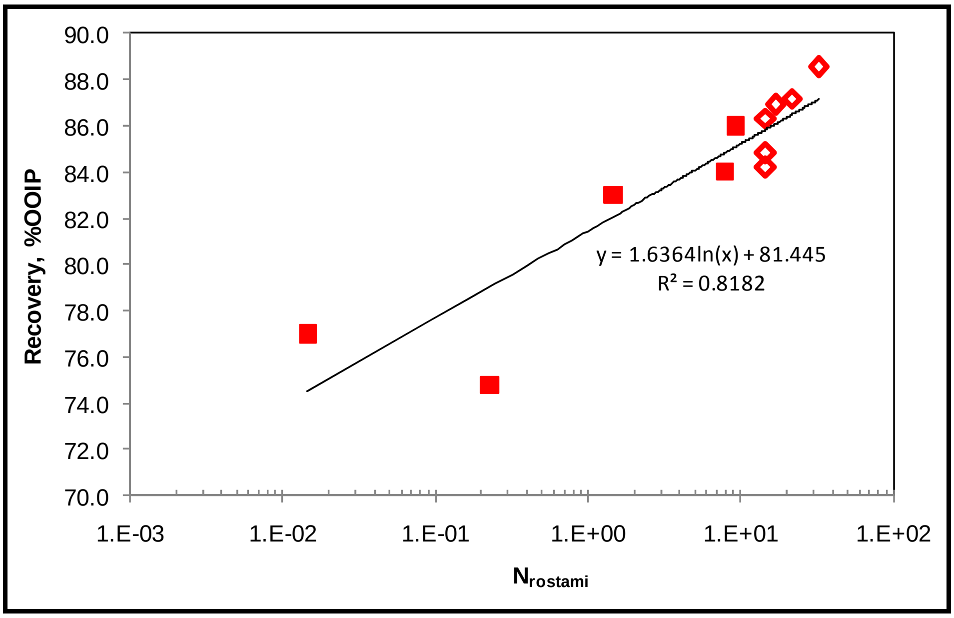

Figure 7-11: Effect of combined model of Rostami (2009) on oil recovery in m*iscible* CO_2-GAGD EOR process. Red squares: N_K - field projects. Red hollow diamonds: $N_{Rostami}$ - this study

7.2.5 New Proposed Model, its Physical Significance and Validation

Oil recovery obtained in the reservoir simulations in this study and the field projects were investigated using the Capillary number (N_C), Bond number (N_B) and the Gravity number (N_B) to develop a correlation that captures important process operational physical properties. Inferences of the oil recovery versus the N_C, N_B and N_G suggest that the oil recovery (% OOIP) in CO_2-assisted gravity drainage EOR process is directly proportional to N_G and N_B whereas it is inversely proportional to the capillary number (N_C).

Results presented in the section 7.2.3 indicated that, although the gravity number provided reasonably accurate and closely matched correlation; there are be other important multiphase parameters that must be considered in this evaluation. With regards to Bond number, it does not have terms that can evaluate the effect of the viscous forces and the viscosity changes taking place during oil recovery in the CO_2-assited gravity drainage EOR process. Therefore it alone will not be sufficient to describe the process operating physics.

Results of the reservoir simulations presented in Chapter-6 shows that, the capillary retention is responsible for the pore-trapping of the oil behind the CO_2 floodfront in the CO_2-assisted gravity drainage oil recovery process, thereby diminishing the oil recovery performance. Therefore capillary force effects must be considered while evaluating the immiscible and miscible process performance. Moreover the results also showed that the oil viscosity changes were more pronounced after gas breakthrough in the CO_2-assisted gravity drainage EOR process (see Figures 5-20, 5-21, 5-22, 6-8, 6-9 6-20, 6-27 and 6-32). **Figure 7-12** suggests that the viscosity ratio (injection gas to the reservoir oil) increase results in the increasing oil recovery. Therefore, these viscosity changes must be considered while developing the new dimensionless number. Moreover, the relative density of the injection gas and reservoir oil greatly influences the gravity drainage oil displacement, so the EOR performance in the CO_2-assisted gravity drainage oil recovery.

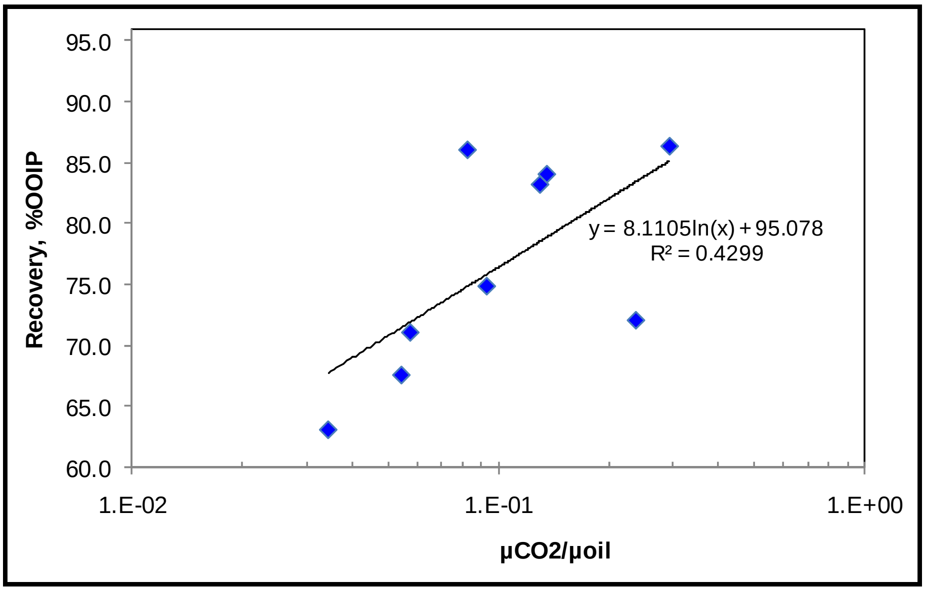

Figure 7-12: Effect of viscosity ratio on the oil recovery in m*iscible* CO_2-GAGD EOR

Investigation of the dimensionless numbers in this study concluded that the oil recovery in the CO_2-assisted gravity drainage EOR process is directly proportional to N_G and N_B whereas it is inversely proportional to the capillary number (N_C). On the other hand, Kulkarni number (N_K) indicated that the oil recovery is directly proportional to the N_C. This observation contradicts the finding in this study, although the combination number suggested by Kulkarni (2005) provided very good match in this study. Based on the relative inferences of these groups with the oil recovery, it is concluded that the

Kulkarni number (N_K) may not appropriate to evaluate the performance of the CO_2-assisted gravity drainage EOR process.

Rostami *et al.* (2009) presented a combination number in which the oil recovery is depicted to be directly proportional to N_B and inversely proportional to the N_C. Furthermore, the oil recovery performance presented in the **Figure 7-10** and **Figure 7-11** using Rostami model did not yield in the satisfactory match. This could be attributed to the non-inclusion of the gravity number term (N_B) in their model. Conversely, the investigations of the results presented in the current study in this thesis suggests that the gravity number N_G term is important before the gas breakthrough and the gas floodfront arrival, whereas the interplay of the gravity and the capillary forces represented by the Bond number N_B is of paramount importance after the gas floodfront arrival.

Keeping in mind the above findings, a new correlation is developed in this study to characterize and evaluate the performance of CO_2-assisted gravity drainage EOR process. Capillary number (N_C), Bond number (N_B) and Gravity number (N_G) along with the density and viscosity ratio are factored in this correlation. The newly developed combination dimensionless group is presented as:

$$N_{Jadhawar\ and\ Sarma} = \frac{(x)(N_G + N_B)}{(y)^a\ N_C{}^b} \quad \text{.......(7.6)}$$

where

$$x = \frac{\rho_{CO2}}{\rho_{Oil}}$$

$$y = \frac{1}{\mu_r}$$

$$\mu_r = \frac{\mu_{CO2}}{\mu_{Oil}}$$

$$a = b = 0.2$$

Parameters ‘a’ and ‘b’ in above correlation are the scaling factors. Oil recovery obtained in immiscible and miscible CO_2-assisted gravity drainage EOR process is presented in **Figure 7-13** and **Figure 7-14** respectively. Oil recovery presented in these figures is at the scaling factors of 0.2. Smaller values of these scaling factors (less than 1.0) outline the greater importance and significance of the gravity and bond numbers compared to the capillary number and viscosity ratio prevailing in the immiscible and miscible gravity drainage process. However, these scaling factors would be different for the oil recovery at different pore volumes of the CO_2 injected.

Using new proposed combination dimensionless group, the immiscible oil recoveries obtained in this reservoir simulations studies (green hollow diamonds) yielded excellent match with the four immiscible field projects data (green squares) (**Figure 7-13**). Miscible oil recoveries presented in **Figure 7-14** also provided an excellent correlation amongst the simulation results in this study and the field project data. Reservoir simulation results from three porous media with different permeabilities of 1200 mD, 120 mD and 1.2 mD were also included in this study.

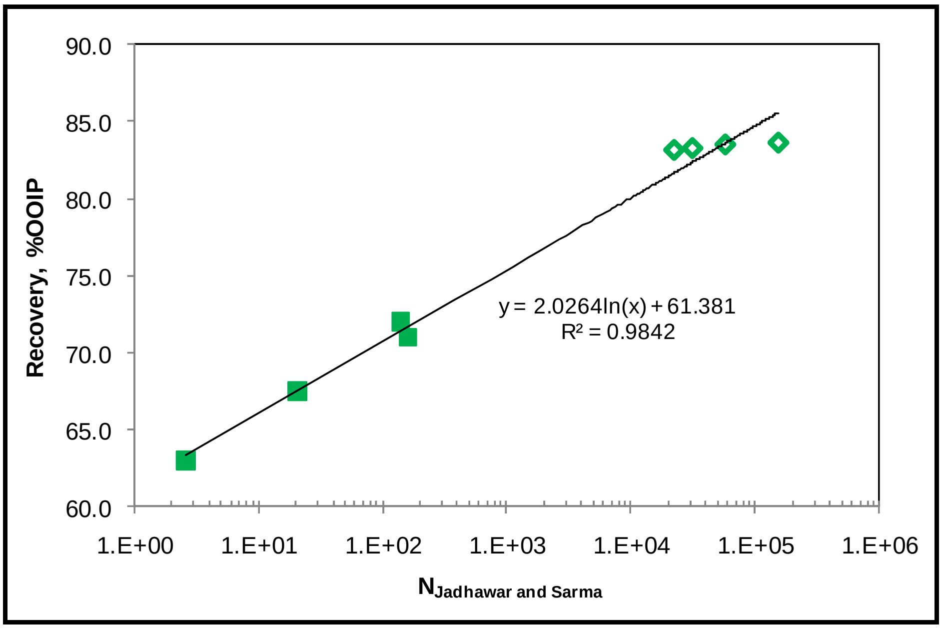

Figure 7-13: Effect of new scaled model on oil recovery in the *immiscible* CO_2-GAGD EOR process. Green squares: $N_{\text{Jadhawar and Sarma}}$ - field projects. Green hollow diamonds: $N_{\text{Jadhawar and Sarma}}$ - this study

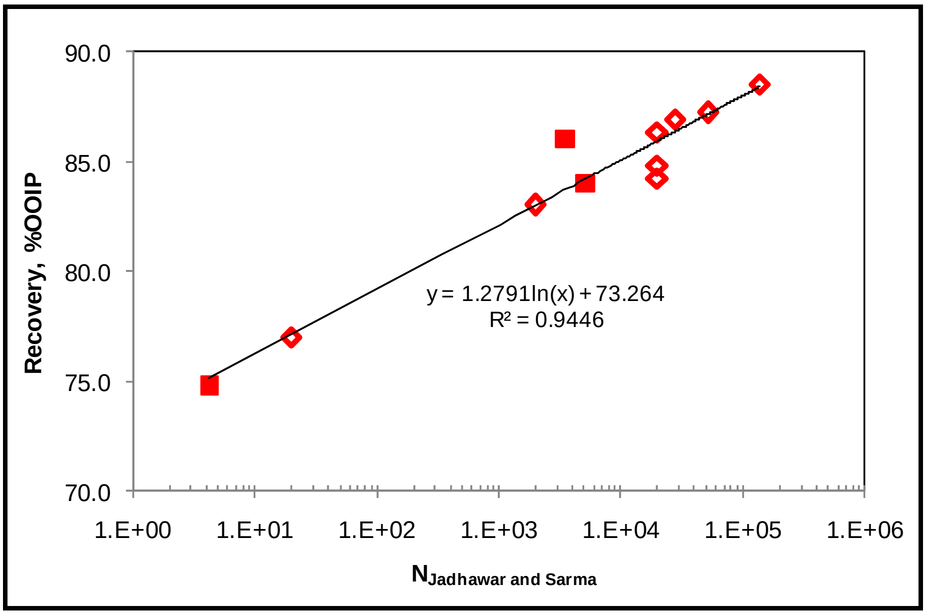

Figure 7-14: Effect of new scaled model on oil recovery in the *miscible* CO_2-GAGD EOR process. Red squares: $N_{Jadhawar\ and\ Sarma}$ - field projects. Red hollow diamonds: $N_{Jadhawar\ and\ Sarma}$ - this study

These results presented in both the immiscible and miscible processes suggest that there exists an excellent logarithmic relationship between the oil recovery and the newly developed dimensionless number ($N_{Jadhawar\ and\ Sarma}$) with very low data dispersion. Although this new dimensionless number looks more complex, the reasonably accurate match of the simulation and field data further pointed out that new number is able to capture the important multiphase operational mechanistic parameters in both homogeneous (1200 mD; k_v/k_h=1.0) and heterogeneous (120 mD; k_v/k_h=0.1 and 1.2 mD; k_v/k_h=0.001) permeable media. Moreover, the prime significance of this new correlation lies in that it can be used to predict the oil recoveries for the CO_2-assisted gravity drainage field projects, provided the data required for the calculation of the involved dimensionless groups is available.

7.3 Scaling and Sensitivity Based on the Developed Scaling Groups: 35 ^{o}API Reservoir

In this section, an immiscible CO_2-assisted gravity drainage EOR process is evaluated through scaling and sensitivity analysis using the uncertainty assessment technique to investigate relationship between the scaling groups and their effect on the overall oil recovery performance. This analysis is performed using the multiphase parameters assigned in the reservoir simulations on 35 ^{o}API gravity reservoir.

Main objective is to study the CO_2-assisted gravity drainage oil recovery performance through scaling approach in an immiscible process subjected to non-dipping horizontal type reservoir. The knowledge of parameters that influence the overall gravity drainage oil recovery is essential while selecting the scaling groups for the sensitivity analysis. Since the CO_2-assisted gravity drainage EOR method is a top-down process, higher vertical permeability is favoured for the selected reservoir candidates. As the recovery method is driven by the gravity force, it is imperative that the dimensionless groups that have the critical parameters contributing to gravity (density) should be included in the scaling.

In the respective reservoir simulations conducted in this study (section 5.2.1 of Chapter-5) the rate of gas injection (i_g) is maintained constant for a particular recovery operation (Case-II presented in **Table 5-1**). This i_g contributes to the relative fluid velocities within the reservoir. During these gas injection operations, pressures of the injection wells and producing wells have been kept constant. Other important operational multiphase parameters include the relative mobilities and viscosities of the all operational phases (oil, water and gas) and residual oil saturations of water and gas. Keeping in mind these considerations with regards to CO_2-assisted gravity drainage EOR method, the scaling groups are obtained through the dimensionless analysis.

Rigorous inspectional analysis procedures carried out in the previous studies for dipping reservoirs (Gharbi *et al.*, 1998; Shook *et al.*, 1992) to produced dimensionless scaling groups that can be modified to implement sensitivity analysis for the horizontal type reservoir under investigation in this study. Secondary waterflooding based gravity number (ratio of the gravity to the viscous forces) from Shook *et al.* (2002) is dependent on the rate of the water injection. To consider the CO_2-assisted gravity drainage EOR process dependent constant pressures condition of the injection wells and the production wells, and the highly compressible nature of the injectant (CO_2), the gravity number is modified to make it applicable to the horizontal type reservoir. Saturation groups are included in the scaling group to study the better understanding for the quantification of the oil recovered.

Procedure of Buckingham (1914) was employed to develop dimensionless groups developed through and are tabulated in **Table 7-4**. Individual groups from this table can be combined to form the dimensionless groups that are particularly required for the scaling and sensitivity analysis. Such dimensionless groups are presented in **Table 7-5** used to scale the CO_2-assisted gravity drainage EOR process.

Table 7-4: Dimensionless Groups obtained through Buckingham-Pi Analysis

Sr. No	Dimensionless π Group	Sr. No	Dimensionless π Group	Sr. No	Dimensionless π Group	Sr. No	Dimensionless π Group
π_1	$\frac{L}{\sqrt{k_v}}$	π_{12}	$\frac{P_{MM}}{\Delta P}$	π_{23}	$\frac{\sigma_{OG}}{\Delta P\sqrt{k_v}}$	π_{34}	$\frac{\rho_o}{\Delta\rho}$
π_2	$\frac{W}{\sqrt{k_v}}$	π_{13}	$\frac{P_R}{\Delta P}$	π_{24}	$\frac{\sigma_{WG}}{\Delta P\sqrt{k_v}}$	π_{35}	$\frac{\rho_w}{\Delta\rho}$
π_3	$\frac{H}{\sqrt{k_v}}$	π_{14}	$D\sqrt{\frac{\Delta\rho}{\Delta P.k_v}}$	π_{25}	$\frac{\Delta\rho.g\sqrt{k_v}}{\Delta P}$	π_{36}	$\frac{\rho_g}{\Delta\rho}$
π_4	$t\sqrt{\frac{\Delta P}{\Delta\rho.k_v}}$	π_{15}	$K_T\sqrt{\frac{\Delta\rho}{\Delta P.k_v}}$	π_{26}	$\frac{I_G}{k_v}\sqrt{\frac{\Delta\rho}{\Delta P}}$	π_{37}	S_{wc}
π_5	$u_T\sqrt{\frac{\Delta\rho}{\Delta P}}$	π_{16}	$K_L\sqrt{\frac{\Delta\rho}{\Delta P.k_v}}$	π_{27}	$\frac{q_O}{k_v}\sqrt{\frac{\Delta\rho}{\Delta P}}$	π_{38}	S_{orw}
π_6	$\frac{V_p}{k_v^{1.5}}$	π_{17}	$\frac{d}{\sqrt{k_v}}$	π_{28}	$\frac{\mu_o}{\sqrt{\Delta\rho.\Delta P.k_v}}$	π_{39}	S_{org}
π_7	$\frac{V_b}{k_v^{1.5}}$	π_{18}	$\frac{k_h}{k_v}$	π_{29}	$\frac{\mu_g}{\sqrt{\Delta\rho.\Delta P.k_v}}$	π_{40}	ϕ
π_8	$\frac{FV}{k_v^{1.5}}$	π_{19}	$\frac{k_{rw}}{k_v}$	π_{30}	$\frac{\mu_w}{\sqrt{\Delta\rho.\Delta P.k_v}}$	π_{41}	$\propto$
π_9	$\frac{P_{IG}}{\Delta P}$	π_{20}	$\frac{k_{ro}}{k_v}$	π_{31}	$\lambda_o\sqrt{\frac{\Delta\rho.\Delta P}{k_v}}$	π_{41a}	$\tan\propto$
π_{10}	$\frac{P_{op}}{\Delta P}$	π_{21}	$\frac{k_{rg}}{k_v}$	π_{32}	$\lambda_g\sqrt{\frac{\Delta\rho.\Delta P}{k_v}}$		
π_{11}	$\frac{P_C}{\Delta P}$	π_{22}	$\frac{\sigma_{OW}}{\Delta P\sqrt{k_v}}$	π_{33}	$\lambda_w\sqrt{\frac{\Delta\rho.\Delta P}{k_v}}$		

Table 7-5: Dimensionless groups used in scaling the immiscible CO_2-assisted gravity drainage EOR process (35 API reservoir)

Eq. No.	Dimensionless scaling group	Correlation
7.7	Aspect Ratio	$R_L = \frac{L}{H}\sqrt{\frac{k_z}{k_x}}$
7.8	Dip angle	$N_\alpha = \frac{L}{H}\tan\alpha$
7.9	Gravity Number: Injection rate based	$N_{gI} = \frac{H}{L}\frac{k_v \lambda_{ro} \Delta\rho g}{u_T}$
7.10	New Gravity Number: Pressure based	$N_{gP} = \frac{H\Delta\rho g}{\Delta P}$
7.11	Mobility ratio: Water-Oil (M_{wo})	$M_{wo} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$
7.12	Mobility ratio: Gas-Oil (M_{go})	$M_{go} = \frac{k_{rg}/\mu_g}{k_{ro}/\mu_o}$
7.13	Injection pressure group	$P_{injD} = \frac{P_{inj}}{P_{MM}}$
7.14	Producing pressure group	$P_{prodD} = \frac{P_{prod}}{P_{MM}}$
7.15	Residual oil saturation to water (water-oil system)	S_{orw}
7.16	Residual oil saturation to gas (gas-oil system)	S_{org}

7.3.1 Sensitivity Studies

In sensitivity analysis, the dimensionless groups (equation 7.7 to 7.16) detailed in **Table 7-5** are used to study the performance of CO_2-assisted gravity drainage EOR method. Immiscible process performance is scaled for the first time through the dimensionless scaling groups especially using gas injection and production pressures at the respective wells and gravity number dependent on the difference of the pressure between injection and producing well. Operational parameters are varied systematically over the ranges of values. Data of the multiphase parameters required for the scaling studies is generated using CMG's IMEX simulator. Dimensionless groups are then used to study the sensitivity of individual parameters by varying their values. The values of the parameters are then varied such that the final dimensionless group values remain constant to validate their application to the CO_2-assisted gravity drainage EOR method.

In sensitivity studies, the value of each scaling group under consideration representing CO_2-assisted gravity drainage EOR process is calculated. Using data obtained in the reservoir simulations for each individually-changed parameter in each of the group, the fractional oil recovery in the form of dimensionless recovery (R_D) over the dimensionless time (t_D) for each of the case is obtained. The dimensionless recovery (R_D) is the percentage of the available oil in place (for CO_2-assisted gravity drainage EOR process) recovered after the CO_2 injection whereas the dimensionless time (t_D) is ratio of the cumulative CO_2 volume injected and pore volume. In all sensitivity studies, Case-II (**Table 7-6**) is taken as the basis for varying the parametric values in the scaling group under consideration thereby keeping the values of other scaling groups constant.

7.3.2 Gravity Number Group

Depth, height and vertical permeability of the reservoir, relative permeability and viscosity of the oil, difference of the density between the oil and injected gas, gravity and total superficial velocity of the fluids constitutes the gravity number that is based on the constant gas injection rate constraint (see Equation 7.9 in **Table 7-5**). Risk analysis of these parameters showed that superficial velocity is the most critical parameter followed by constant vertical permeability and the injected gas and oil density difference in CO_2-assisted gravity drainage EOR process for the setting given in **Table 7-6**. Therefore, average total superficial velocity of the fluids is adapted from IMEX simulations while studying the sensitivity of gravity number. It's variation with the dimensionless recovery at three injection rates (Case-I to Case-III) is as shown in **Figure 7-15**. u_T increases with the higher injection rates. For a particular injection rate, it increases gradually yielding nearly stable gravity number (**Figure 7-16**). With the further advancement of gas floodfront towards the wellbore, uT increased at higher rates. Corresponding gravity number further decreased. It sharply rises after the gas breakthrough. With each successive higher gas injection rate combination, the lower gravity number responses were observed. These results suggest that the gravity number is sensitive to the superficial velocity (gas injection rates) changes, which is in agreement with the risk analysis on the gravity number. Respective gravity drainage oil recovery performance is analyzed by constructing dimensionless recovery (R_D) vs. dimensionless time (t_D) (**Figure 7-16**). At low gravity numbers, higher dimensionless recoveries are obtained as seen in Case-I. For the higher gravity number Case-III, lower oil recoveries were obtained. This suggests that the dimensionless recoveries are inversely proportional to the gravity number especially with the gravity number based on the superficial velocity, u_T. Nevertheless, gravity number variation in all the cases is not very significant owing to the dominating gravity drainage oil recovery mechanism.

Table 7-6: Multiphase operational parameters considered for the sensitivity analysis of CO_2-GAGD EOR process. Group value of one of the scaling group is varied while keeping others constant

Parameters	Case-I	Case-II	Case-III	Groups	Case-I	Case-II	Case-III
L (ft)	30000	**30000**	30000	RL	20	20	20
w (ft)	12000	**12000**	12000	Nα	0	0	0
H (ft)	1500	**1500**	1500	Mw	0.21	0.21	0.21
P (psia)	3837	**3837**	3837	Mg	1.36	1.36	1.36
T (°F)	180	**180**	180	Soi	0.85	0.85	0.85
k_V (md)	1200	**1200**	1200	Sorw	0.2	0.2	0.2
k_H (md)	1200	**1200**	1200	Sorg	0.1	0.1	0.1
ρ_o (lb/ft^3)	53.002	**53.002**	53.002				
ρ_{CO2} (lb/ft^3)	0.1148	**0.1148**	0.1148				
μ_o (cP)	0.2026	**0.2026**	0.2026				
μ_w (cP)	0.3687	**0.3687**	0.3687				
μ_{CO2} (cP)	0.056	**0.056**	0.056				
k_{rw}	0.3	**0.3**	0.3				
k_{ro}	0.8	**0.8**	0.8				
k_{rg}	0.3	**0.3**	0.3				
I_{CO2}(SCFD)	5.10E+07	**6.75E+07**	9.00E+07				

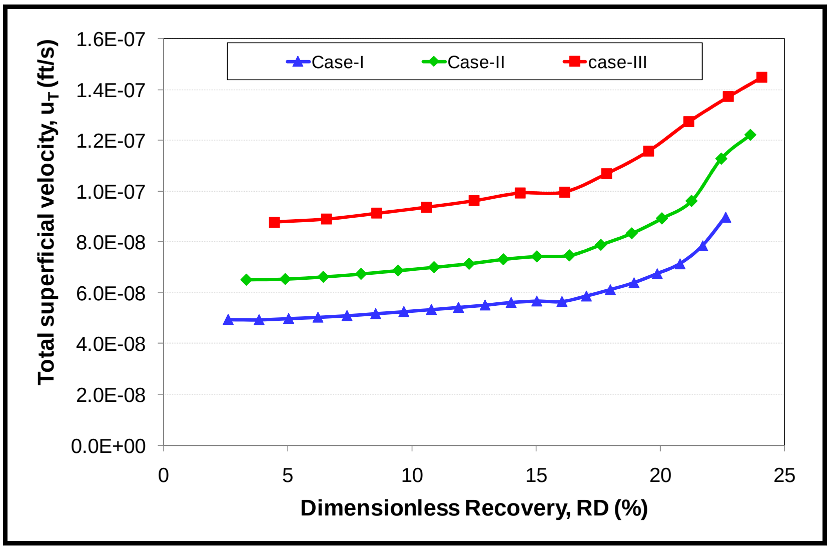

Figure 7-15: Total superficial velocity (u_T) vs dimensionless recovery (R_D)

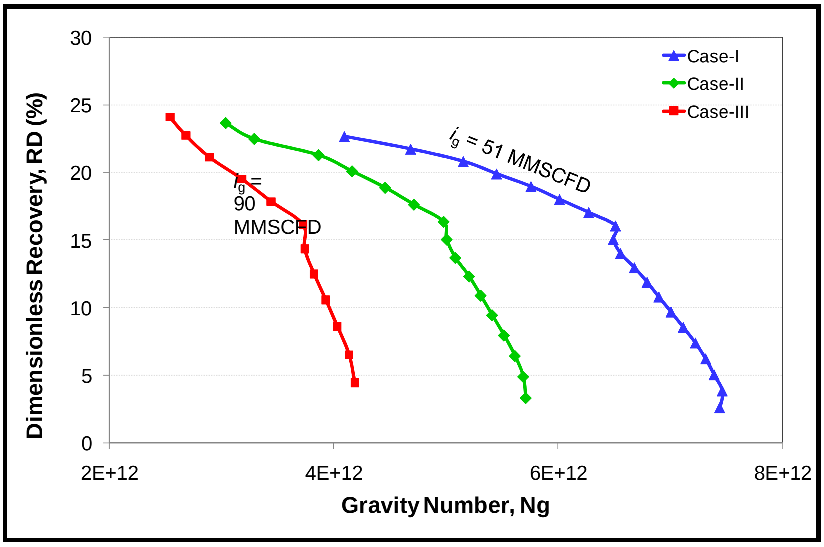

Figure 7-16: Effect of the i_g based N_g on the dimensionless CO_2-assisted gravity drainage oil recovery

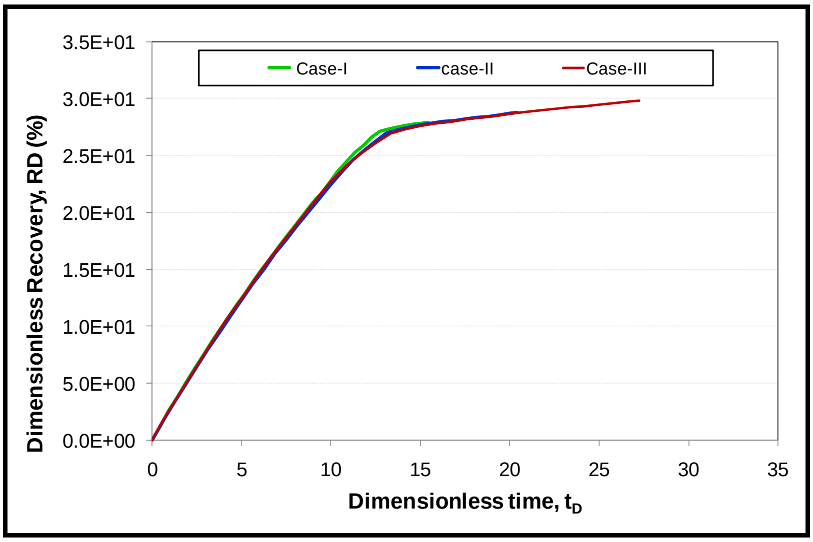

Figure 7-17: Dimensionless oil recovery performance of CO_2-assisted gravity drainage EOR process over the respective Pore values of CO_2 injected: Gravity number (i_g based)

Gravity drainage oil recovery is based on the constant gas injection and oil producing pressure as well. Therefore the gravity number based on these parameters is obtained by converting the gas injection rate constraints to the pressure constraints. The term describing the potential difference across the reservoir due to viscous forces ($u_T.L/k_v.\lambda$) is replaced by the difference of pressure between the gas injection and the oil production well (P_{inj}-P_{prod}). Respective dimensionless group developed is represented by the equation 7.10 as shown in **Table 7-6**. Three sample reservoirs with the pressure based gravity numbers of 1.7E+04, 1.16E+04 and 8.2E+03 are created for three different pressure combinations of injection and production wells, so as to have their difference as 150 psi, 220 psi and 310 psi respectively. Reservoirs having multiphase parameters given in Case-II of **Table 7-6** are used in this study while keeping other scaling group values constant. Dimensionless recovery performance of these sample reservoirs at three pressure settings are presented in **Figure 7-18**. From this Figure, it is seen that the dimensionless recovery at three different pressure settings yields very close agreement of the reservoir performance at the same pore volumes of CO_2 injected. In spite of having three different gravity number values at the respective pressure settings, very low data dispersion in terms of the dimensionless recovery suggests that the pressure dependent gravity number would be more appropriate to apply while investigating the CO_2-assited gravity drainage EOR process performance.

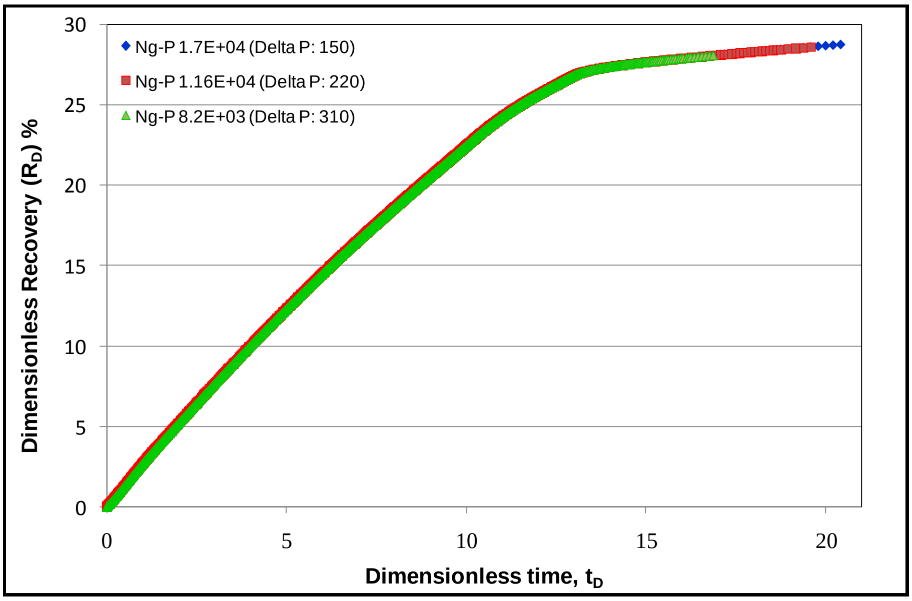

Figure 7-18: Dimensionless oil recovery performance of CO_2-assisted gravity drainage EOR process over the respective Pore values of CO_2 injected: Pressure based Gravity number

7.3.3 Pressure Group

Three combinations of the injection and producing well pressures are used in studying effect of the pressure group (Equation 7.13 and 7.14 in **Table 7-5**) on the oil recovery in the CO_2-assisted gravity drainage EOR process. They are 2800 psia and 2650 psia, 2750 and 2550 psia, and 2700 psia and 2450 psia. Respective dimensionless group values of injection and producing pressure groups are 0.5253 and 0.4767, 0.5350 and 0.4961; and 0.5447 and 0.5156 respectively. Values of other scaling groups are kept constant (Case-II combination shown in **Table 7-6**).

Figure 7-19 shows the dimensional recovery performance of the CO_2-assisted gravity drainage EOR process at these three injection and producing pressure groups. At higher values of the injection and producing pressure group, a lower recovery is obtained. At lower pressure combination, the oil recovery yield is higher with a delayed production of about 7 years compared to the highest pressure group combination. Flattened recovery curves are the oil recoveries obtained after gas breakthrough arising from the capillary retention of the oil left behind CO_2-floodfront. Results obtained in this study shoes that the amount of oil displaced in the GAGD-EOR process is inversely related to pressure at the gas injection and oil production well, so the injection pressure and production pressure group.

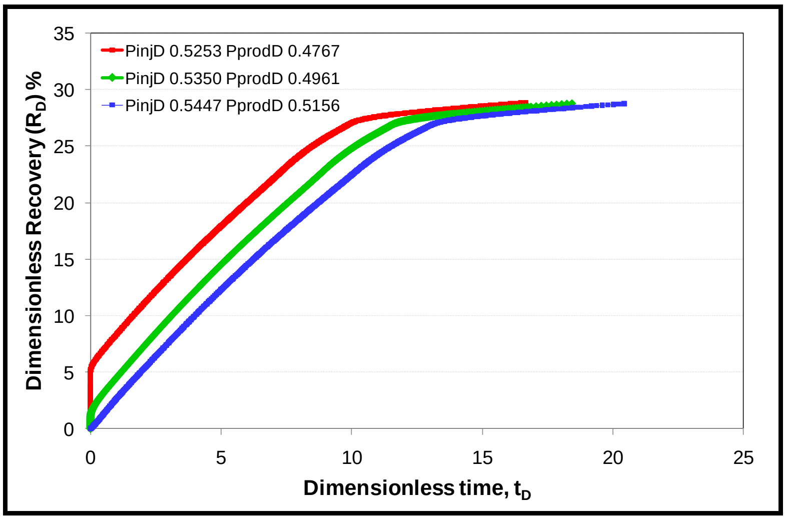

Figure 7-19: Effect of pressure group on EOR performance in the CO_2-assisted gravity drainage EOR process. Other scaling group values are kept constant.

7.3.4 Mobility Ratio Group

Mobility ratio represents the relative mobility of phases (oil, gas and water) present in the reservoir. Movement of the oil, gas and water at reservoir conditions play an important role on the outcome of the recovery performance of the water and gas injection operations. Unfavourable mobilities of these phases results in oil bypassing, viscous fingering, and channelling effects. Sensitivity of mobility ratios on the CO_2-assisted gravity drainage EOR process is studied in three settings using Equations 7.11 and 7.12 as shown in **Table 7-5**. Values of other scaling groups are kept constant (**Table 7-6**).

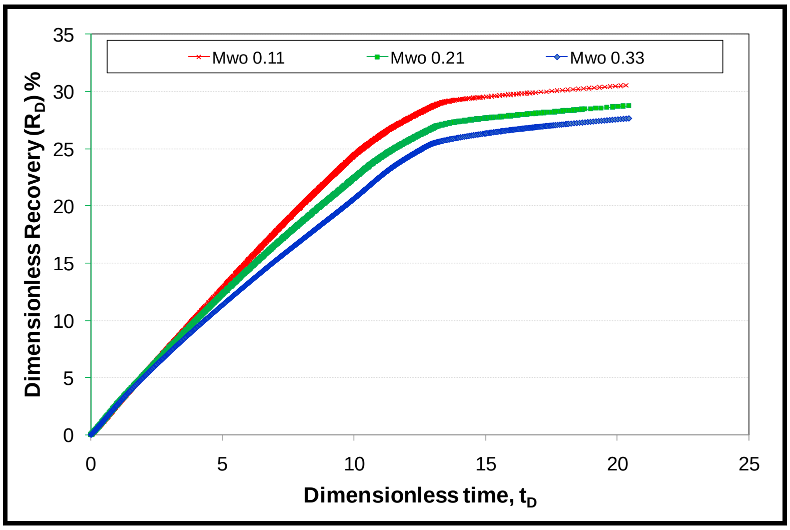

Figure 7-20: Effect of water-oil mobility ratio (M_{wo}) on EOR performance in CO_2-assisted gravity drainage EOR process. Other Scaling group values are kept constant.

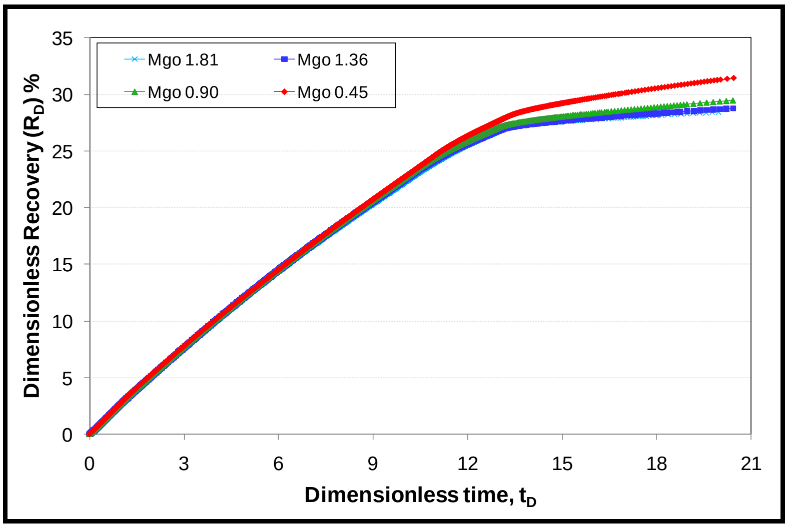

Figure 7-21: Effect of gas-oil mobility ratio (M_{wo}) on EOR performance in the CO_2-assisted gravity drainage process. Other Scaling group values are kept constant.

For the sensitivity studies of the water-oil mobility ratio (M_{wo}), relative permeability of water is varied from 0.18, 0.3 and 0.48 while relative permeability to oil is kept constant at 0.8. Other dimensionless group values were maintained constant (see **Table 7-6**). Dimensionless recovery performance over the dimensionless time is as shown in **Figure 7-20**. Results presented in indicate that water-oil mobility ratio of three cases start to differ after few years of the production, which continue to rise in the later stage of the flooding operations. Higher oil recovery is obtained at lower M_{wo} suggesting that the dimensionless oil recovery is inversely proportional to the water-oil mobility ratio in the CO_2-assisted gravity drainage EOR process.

For gas (CO_2)-oil mobility sensitivity study, four sample reservoirs were created with the scaling group values of 0.45, 0.90, 1.36 and 1.81 by varying the relative gas permeability as 0.1, 0.2, 0.3 and 0.4. Dimensionless recoveries obtained over the dimensionless time are as depicted in **Figure 7-21**. Dimensionless recovery performance curves start to differ from each other in the middle of flooding operations. It becomes more pronounced in the last quarter of the CO_2 flooding, which further increases after gas breakthrough (flattened portion of the curve). This is in contrast with the flood performance of the water-oil mobility ratio. Deviations between the individual recoveries were high in the middle of the flood which continues to rise. In case of gas-oil mobility ratio, the lower relative mobility of CO_2 to displace the oil in the reservoir downward towards the producing wells is critical for the success of CO_2-assisted gravity drainage EOR method.

7.3.5 Residual Oil Saturations

Effect of the changes in residual oil saturation to water (S_{orw}) and gas (S_{org}) on the gravity drainage oil recovery is studied through the sensitivity analysis. Residual oil saturation to water is varied in three cases mainly, 0.2, 0.25 and 0.3 while residual oil saturation to gas is varied as 0.1, 0.2 and 0.3. Other dimensionless scaling group values are kept constant (**Table 7-6**). Results are presented in **Figure 7-22** for the residual oil saturation to water and **Figure 7-23** for the residual oil saturation to gas.

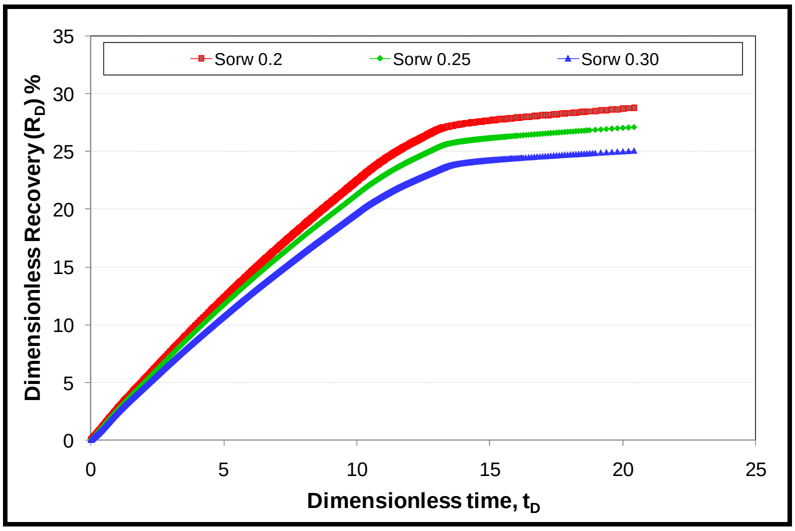

Figure 7-22: Sensitivity of the residual oil saturations to water (S_{orw}) on the oil recovery performance in the CO_2-assisted gravity drainage EOR process

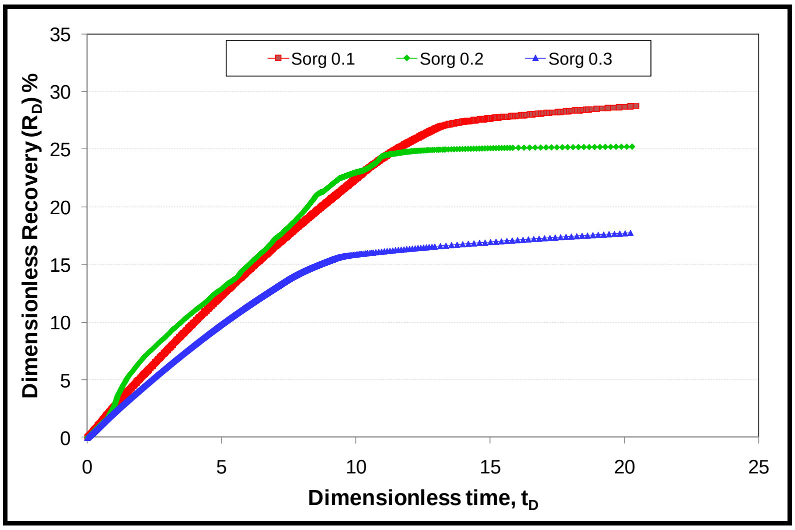

Figure 7-23: Sensitivity of the residual oil saturations to gas (S_{org}) on oil recovery performance in the CO_2-assisted gravity drainage EOR process

Results represented in the form of dimensionless oil recovery (R_D%) over the dimensionless time (t_D) showed that the residual oil saturation to water and gas has considerable impact even with a minor variation in their values. **Figure 7-22** shows that the dimensionless recovery (R_D%) is low for the higher S_{orw} values. It begins to deviate right from the start of CO_2 flooding operations from other dimensionless recoveries of the lower residual oil saturations. For the residual oil saturation of gas, these deviations are higher. At the lower residual oil saturation to gas, very high dimensionless oil recovery is obtained compared to the residual oil saturation to water. Flattened shape of the curves represents the oil recoveries after CO_2 breakthrough. Lower residual oil saturation to gas delays the gas breakthrough. For S_{org} of 0.1 it is delayed by t_D of 2 and 4 compared to the respective t_D related to the S_{org} of 0.2 and 0.3 represented by the changed course of the dimensionless recovery curve. It can be therefore concluded that S_{org} is directly proportional to the gravity drainage oil recovery. S_{orw} dimensionless recoveries, the gas breakthrough time was about similar. These results indicate that S_{orw} and S_{org} should be included in the scaling of CO2-assisted gravity drainage EOR process.

7.3.6 Validation of the Scaling Groups

The functional relationship between the dimensionless scaling groups and an immiscible CO_2-assisted gravity drainage oil recovery performance in all of the sensitivity studies is mapped through numerical simulations over the CMG'S IMEX simulator. Now the dimensionless recovery performance obtained through the dimensionless scaling groups should be matched for its validation. To achieve this, the parameters making up the dimensionless scaling groups are changed so that the final values of the all the scaling groups remain unchanged. Dimensionless recoveries of the sample reservoirs with equal dimensionless group values if closely agrees with each other all the times, then these scaling groups could be sufficient to scale the CO_2-assisted gravity drainage EOR process at the field scale.

Individual values of the dimensional properties (of multiphase parameters operational in the CO_2-assisted gravity drainage EOR process) and dimensionless scaling groups are as given in **Table 7-7** and **Table 7-8**, respectively. Vertical and horizontal permeability, end point relative permeabilities of water, oil and gas, saturations of oil, gas and water are changed in three reservoir samples (I, II and III) so that the values of 10 dimensionless scaling groups remain constant. Vertical and horizontal permeability values of the reservoir porous media are varied as 1200 mD, 1050 mD and 1400 mD. Relative permeability of the water, k_{rw} and the relative permeability of gas, k_{rg} values are varied as 0.3, 0.27 and 0.24 whereas k_{ro} values are changed as 0.8, 0.72 and 0.64. Pressures in the gas injection and oil production wells are used in obtaining the final injection pressure group, producing pressure group and the gravity number values. The calculated scaling group values are as given in **Table 7-8**.

Table 7-7: Dimensional properties of three sample reservoirs

Parameters	Reservoir-I	Reservoir-II	Reservoir-III
L (ft)	30000	30000	30000
W (ft)	12000	12000	12000
H (ft)	1500	1500	1500
P (psia)	3837	3837	3837
T (^oF)	180	180	180
k_V (md)	**1200**	**1050**	**1400**
k_H (md)	**1200**	**1050**	**1400**
ρ_o (lb/ft^3)	53.002	53.002	53.002
ρ_{CO2} (lb/ft^3)	0.1148	0.1148	0.1148
μ_o (cP)	0.2026	0.2026	0.2026
μ_w (cP)	0.3687	0.3687	0.3687
μ_{CO2} (cP)	0.056	0.056	0.056
P_i (psia)	2800	2800	2800
P_P (psia)	2650	2650	2650
P_{MM} (psia)	5140	5140	5140
k_{rw}	**0.3**	**0.27**	**0.24**
k_{ro}	**0.8**	**0.72**	**0.64**
k_{rg}	**0.3**	**0.27**	**0.24**

Table 7-8: Dimensionless group values of 3 sample reservoirs, calculated using data in Table 7-7

Scaling groups	Reservoir-I	Reservoir-II	Reservoir-III
R_L	20	20	20
N_α	0	0	0
M_w	0.21	0.21	0.21
M_g	1.36	1.36	1.36
N_{gP}	1.70E+04	1.70E+04	1.70E+04
P_{iD}	0.54	0.54	0.54
P_{PD}	0.52	0.52	0.52
S_{oi}	0.85	0.85	0.85
S_{orw}	0.2	0.2	0.2
S_{org}	0.1	0.1	0.1

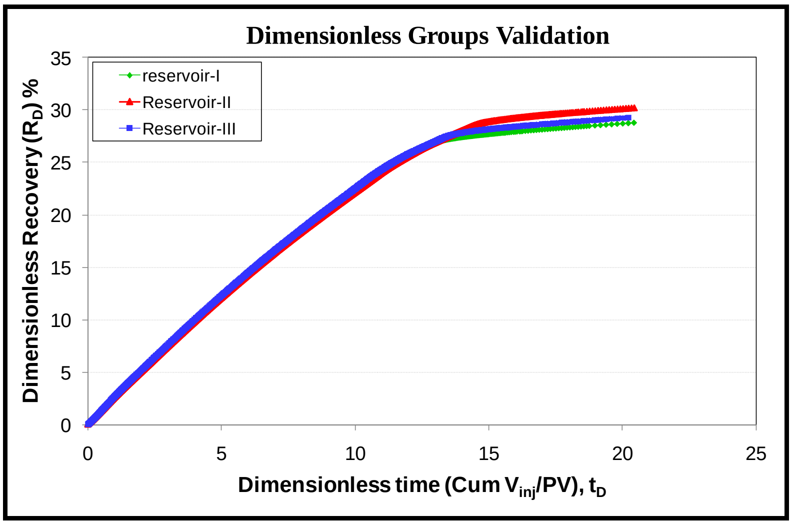

Figure 7-24: Dimensionless oil recovery performances of 3 sample reservoirs. Very similar recoveries represent successful scaling of the CO_2-assisted gravity drainage EOR process.

Performance of the CO_2-assisted gravity drainage EOR process in these three cases in the form of dimensionless recovery is plotted against the dimensionless time for three sample reservoirs as depicted in **Figure 7-24**. CMG's IMEX simulator is used to obtain the data required for validation of the scaling groups. The results depicted in the figure showed that the dimensionless recoveries obtained for all the reservoirs under investigation are identical. Maps produced are in close agreement with each other by just 10-12% variation until CO_2 breakthrough. This indicates that the results in the dimensionless quantities are reproducible. They are independent of scale. Any reservoir with the equal values of these groups should have same dimensionless recovery. Therefore, the results presented in this study further point out that the dimensionless groups that are used to validate the results should be sufficient for scaling the CO_2-assisted gravity drainage EOR process.

7.4 Summary

Results of the reservoir simulation studies conducted in this study (See Chapter-5 and Chapter-6) were evaluated using the traditional dimensionless numbers in this chapter. This evaluation was then compared with the dimensionless numbers calculated using the field data. Based on the findings from this evaluation, a new correlation that captures the operational mechanistic parameters is proposed. It is then validated by comparing the performance of the new model performance from the reservoir simulation results in this study with the field project data. A reasonably accurate data matching with very low data dispersion suggested that the new scaled model, represented by $N_{\text{Jadhawar and Sarma}}$, did able to capture the effects of the mechanistic multiphase parameters operational in the CO_2-assisted gravity drainage EOR process.

Further scaling and sensitivity analysis of the immiscible CO_2-assisted gravity drainage EOR process is conducted using the 10 dimensionless groups presented in **Table 7-5**. Sensitivity of the individual dimensionless groups (see **Table 7-6**) presented in section 7.3 of this Chapter signified their importance in the gravity drainage oil recovery. Therefore they are included to validate and to identify whether they are sufficient in scaling of the CO_2-assisted gravity drainage EOR process. Very close agreement of the dimensionless recovery over the respective dimensionless time lead to the conclusion that they successfully captured the remaining operational parameters.

Validation of new combination model, $N_{\text{Jadhawar and Sarma}}$, using the reservoir simulation data and the gravity drainage field projects; and additional supporting dimensionless groups in three sample reservoirs lead to conclusion that the dimensionless groups presented in this study captures all the operational multiphase parameters necessary to completely scale the CO_2-assisted gravity drainage EOR process.

8 DISCUSSION OF RESULTS

Compositional and black oil reservoir simulations are conducted to develop a production strategy for the oil recovery optimization in CO_2-assisted gravity drainage EOR process. Results so obtained are then investigated through the development of scaled models and sensitivity with regards to their application to CO_2-assisted gravity drainage EOR process. Results obtained in this PhD research are discussed in the following sections of this Chapter.

8.1 Production Strategy Development

In this study, the effect of CO_2 injection (i_g) and/or oil production rates (q_o), well patterns, injection well type, connate water saturation and capillary pressure in the CO_2-assisted gravity drainage EOR process are investigated to develop a better production strategy that would provide optimum oil recovery. In all of the reservoir simulation studies, the CO_2 injection rates are kept lower than the critical and stable gas injection rates to satisfy the floodfront stability criteria of Dumore (1964a).

In *rate-constraint* studies, either of i_g or q_o is varied while keeping another value constant. Results presented in **Figure 5-8** (section 5.2.2) suggests that keeping q_o constant and adjusting the respective i_g yield higher incremental oil recovery than the other constraint-combination. This rate-constraint criterion was used in the subsequent comparative reservoir simulation studies. Further reservoir simulations for the investigation of the *effect of the injection well type* viz. vertical well versus horizontal well, was studied in both the irregular and regular well patterns shown in **Figure 4-8**. Oil recovery performance of 35 ^{o}API reservoir-oil in the irregular well pattern (see **Figure 5-9** in section 5.3.1) indicated that the *type of CO_2 injection well may not be significant factor in the optimization of CO_2-assisted gravity drainage oil recovery*. Instead, the results obtained in the miscible regular pattern studies on 50 ^{o}API gravity reservoir-oil (**Figure 5-11, Figure 5-13** and **Figure 5-14)** suggest that the *horizontal wells might diminish gravity drainage oil recovery*. These outcomes were then included in investigating the effect of well patterns on the CO_2-assisted gravity drainage EOR performance. Irregular and regular well pattern of the vertical gas injection wells and horizontal oil production wells was then applied in this study (section 5.4).

Comparative investigation of the effect of the irregular (IWP) versus regular well patterns (RWP) on the secondary immiscible and miscible CO_2-assisted gravity drainage EOR performance is carried out in this study. **Figure 5-16** shows that CO_2 floodfront arrival was delayed with RWP in immiscible process by 10 and 8 years in Case-III and IV rate-constraint combination. Moreover, the abrupt vertical drop of oil production rate (q_o) at the time when CO_2 floodfront arrived indicated that the RWP maintained the gas-oil contact more horizontal than the IWP thereby producing the maximum of 2.5% higher incremental oil. Further analysis of the results in miscible process provided similar inferences confirming the hypothesis that *RWP would maintain the gas-oil contact more horizontal than IWP*, thus *incurring the benefits of higher incremental oil recovery*. Gas saturation profiles presented in **Figure 5-16C** (immiscible) and **Figure 5-120C** (miscible) shows that the gas did not prematurely breakthrough the oil zone, thereby satisfying the criteria of Dumore and Schols (1974) for the *stable floodfront without the occurrence of viscous fingering*. Furthermore, the maximum pressure drop of 16 & 35 psi in RWP and IWP respectively was observed in the immiscible process (**Figure 5-19A** and **Figure 5-19B**), whereas the miscible process experienced 80 and 100 psi pressure drop (**Figure 5-22A** and **Figure 5-22B**) in 132 years of CO_2 flooding. This low pressure drop profile in RWP of 0.12 to 0.60 psi/year leads to another hypothesis that *RWP aids in effectively maintaining reservoir pressure*. This behaviour thus indicates that the pressure in gas zone behind the gas floodfront would be constant thereby satisfying the Cardwell and Parsons criteria (1949b) of free-fall gravity drainage mechanism of the oil recovery. Therefore, based on the observations in this study, it can be concluded that the *RWP promotes the gravity drainage mechanism to yield higher incremental oil recovery*.

Oil continued to produce even after the gas floodfront arrival (lower rate though) and its breakthrough at the producing wells. However, analysis of the oil recovery characteristics shows that there are distinctively different recovery mechanisms prevalent in immiscible and miscible CO_2-assisted gravity drainage EOR process. Results presented in **Figures 5-23, 5-24** and **5-25** for the blocks (45,24,6), (45,24,6) and (45,24,8) respectively indicates that the *oil film drainage under gravity effect behind the gas floodfront is another important recovery micro-mechanism* in immiscible CO_2 flooding process. Moreover, the evaluation of viscosity reduction and increase occurring during the entire CO_2 flooding operations suggested that the mechanisms of swelling (viscosity reduction), extraction and vaporization of the medium to heavy components of reservoir oil (viscosity increase) do exist in both the immiscible and miscible CO_2-assisted gravity drainage EOR process. How much they are comparatively effective and how they competes each other is investigated in the oil recovery optimization studies in the next Chapter.

Effect of connate water saturation on the gravity drainage oil recovery performance was investigated by varying its value in three settings. Results presented in **Figure 5-26** suggests that the lower the connate water saturation, higher will the gravity drainage oil recovery. Studies regarding the capillary pressure indicate that the consideration of the capillary pressure in the reservoir simulations is important to investigate the interplay of capillary pressure with the other operational parameters in the CO_2-assisted gravity drainage EOR process.

Results obtained in this Chapter helped to identify and implement the production strategy of i_g and q_o constraint-combination, vertical gas injection wells, RWP, capillary pressure and connate water effect; in the oil recovery optimization studies in the next Chapter.

8.2 Oil Recovery Optimization Studies

In an attempt to optimize oil recovery in CO_2-assisted gravity drainage EOR method, the numerical sensitivity studies have been conducted. Main objectives of these investigations were (1) to identify the process mechanisms and develop a general process selection map to choose between the immiscible and miscible recovery process; (2) to study the effects of (i) grid size through grid-refinement studies (ii) miscibility generation (iii) heterogeneity (iv) molecular diffusion (v) mode of gas injection on the CO_2-assisted gravity drainage EOR process. Finally the operational mechanisms contributing the gravity drainage oil recovery in all of the CO_2-assisted gravity methods are identified.

In all of the reservoir simulation studies, the CO_2 injection rates are kept lower than the critical and stable gas injection rates to satisfy the Dumore and Schols criteria (1964a).

8.2.1 Mechanisms Identification and the General Process Selection Map Development

Main objectives of this study were

- To identify oil recovery mechanisms operational in the CO_2-assisted gravity drainage EOR process using seven rate-constraint combinations
- To develop a general immiscible versus miscible process selection map

Seven successively higher well rate-constraint combinations (see **Table 6-1**) were used in this study. Reservoir simulations were conducted using base-model (50 × 30 × 10: 600 ft × 400 ft × 150 ft) in homogeneous porous media having equal vertical and horizontal permeability. Diffusion effects are neglected in this study.

Average reservoir pressure (P_{Ravg}) was the parameter used to identify the common overall oil recovery mechanism in both the immiscible and miscible CO_2-assisted gravity drainage EOR process. Comparison of the average reservoir pressure behaviour in the Case-IV to Case-VII well rate-constraints combinations is presented in **Figure 6-6**. Results in the immiscible process shows that the average reservoir pressure dropped by 0.17, 0.54, 0.26 and 0.77 psi/year (less than 1 psi/year) respectively from Case-IV to Case-VII well rate-constraint combination in 132 years of CO_2 flooding. In all the cases, reservoir produced with the single phase oil flow at solution GOR with the higher pressure drop before the gas floodfront arrival, indicating the Buckley-Leverett (1942) piston type displacement in the oil zone until gas floodfront arrival (gas breakthrough). Moreover, very low pressure drop behaviour indicated that the average reservoir pressure behind the gas floodfront, that is gas-oil contact (GOC), would be constant. This satisfies the Cardwell Parsons criteria (1949b) of free-fall gravity drainage. Even after gas floodfront arrival the reservoir pressure drop is very small which is further suggestive of the free-fall gravity drainage mechanism of oil recovery. Based on these inferences, it can be concluded that the *prevailing overall mechanism in immiscible CO_2-assisted gravity EOR process, that is responsible for the enhanced oil recovery is the free-fall gravity drainage mechanism*.

In high pressure miscible CO_2 flooding, reservoir pressure drop behaviour is more pronounced. It drops by 1.27, 2.22, 4.36 and 5.33 psi/year until CO_2 floodfront arrival, which is considerably higher than the one observed in immiscible process. Single oil phase flow at solution GOR was observed during this phase, suggestive of the Buckley-Leverett (1942) piston type displacement ahead of the miscible zone. Even these pressure drops are very low at the field scale. Therefore, pressure behind the miscible front in the gas zone would be constant to satisfy the Cardwell Parsons criteria (1949b) of free-fall gravity drainage. After CO_2 floodfront arrival, the average reservoir pressure remained constant to suggest free gravity drainage mechanism. Based on the inferences in this study, it can be concluded that the *miscible process oil recovery proceeds with the Buckley-Leverett piston-type displacement in the oil zone until the arrival of the leading edge of the CO_2 floodfront and free gravity drainage behind in the gas zone*.

Similar inferences of mechanisms in both the immiscible and miscible CO_2-assisted gravity drainage EOR process were noted during the production strategy development studies in the earlier Chapter.

CO_2-assisted gravity drainage EOR process is also studied to investigate the presence of other concurrently operational micro-mechanisms. Oil saturation profile over the entire immiscible CO_2 flood presented in **Figure 6-7A** and **Figure 6-7B** in the block (21, 20,7) demonstrated that oil continued to be recovered at the reduced rate, even after CO_2 floodfront arrival. Oil blobs get interconnected to form thin layers (films) between the continuous gas phase (instead of water phase in tertiary CO_2 injection) and immobile water phase. This thermodynamically stable film improves relative permeability to oil to facilitate the high permeability pathways for the effective oil drainage under the prevalent free-fall gravity drainage behind the CO_2 floodfront. Oil from the displaced oil zone is thus drained under gravity downward towards the horizontal producers through these oil films.

However, the recovery obtained through "oil-film drainage" is found to be very slow in comparison with the miscible process mechanism of the "oil extraction and vaporization by CO_2". Results presented in the form of gas saturation, oil viscosity and oil saturation in **Figures 6-8A, 6-8B** and **6-8C**, **6-9** [blocks: (25,14,6), (25,14,7) and (25,14,8)] and **6-10** (block: 21,20,7) demonstrated that the extraction and/or vaporization mechanism in miscible flood recovers the same volume of oil in 32 and 15 years (**Figure 6-10**) compared to 125 and 64 years in the immiscible flood (**Figure 6-7**) from the block (21,20,7). These results clearly point that the oil extraction and/or vaporization mechanism is much efficient mechanism that is capable of yielding considerably faster oil recovery from the displaced oil-zone (behind the gas floodfront) compared to the oil film flow drainage mechanism in immiscible flood, thereby saving the operational costs of the project. These findings are further evidenced by much higher incremental recovery obtained in miscible process than the immiscible process after gas breakthrough. Conversely, immiscible CO_2 flood yield higher recovery than the miscible process recovery before gas floodfront arrival.

A general map to aid in the selection of the CO_2 flooding between the immiscible or miscible process is prepared based on the ultimate incremental recoveries. If CO_2-EOR operations are constricted by the limits on GOR values (for example: 20000), then this “general selection criteria map” clearly indicate that the miscibility generation may not be a pre-requisite criteria for the optimum CO_2-assisted gravity drainage oil recovery. In this case, very low injection of pore volumes of CO_2 may be required in the flooding process.

8.2.2 Effect of Grid Size through the Grid Refinement Studies

Numerical simulations using the base model (50 × 30 × 10: 600 ft × 400 ft × 150 ft) lead to the generation of a map (**Figure 6-13**) that would provide guideline to select between the immiscible or miscible CO_2-assisted gravity drainage EOR process. Moreover, it concluded that this base model yields the optimum oil recovery of 69.15% and 78.85% in the immiscible and miscible process respectively over 132 years CO_2 injection.

In studying the effect of grid size on the incremental oil recovery, x and y dimensions of grid are reduced by half (300 ft × 200 ft) in Case-IV and Case-VII well rate-constraint combinations from the base-model dimensions (600 ft × 400 ft). **Figure 6-14A** shows that the reduced size model (300 ft × 200 ft × 150 ft) yield an identical incremental oil recovery of 79% compared to the base model (600 ft × 400 ft × 150 ft) at the same 180 pore volumes of CO_2 injected. A similar identical oil recovery profile (60%) was obtained with Case-IV at 45% of PV_{CO2} injected (**Figure 6-15A**). These results in both the well rate-constraint combination point out that the grid size has minimal effect on incremental recovery in the CO_2-assisted gravity drainage EOR process at reservoir scale. Similar results were presented by Fassihi and Gillham (1993) in air injection studies when they varied only the x-dimension length.

Grid thickness is reduced to 50 ft compared to the base case model thickness of 150 ft. CO_2-assisted gravity drainage incremental oil recovery performance indicates that the reduced thickness model yield 6 (Case-VII) to 16% (case-IV) higher incremental oil recovery compared to the base model oil recovery (see **Figure 6-16A**). These results point out that the smaller grid (layer) thickness models provide better incremental EOR profile at the lower pore volumes of CO_2 injected. It facilitates the effective drainage of oil that has been gravity-drained from upper layers to the layers beneath. Moreover, the oil held up in these grid-blocks is prevented. This matters most especially in the layer in which the horizontal well is completed. In contrast, the results of Fassihi and Gillham (1993) and Ypma (1985) suggested that the bottom most layers should be thinner for optimizing the oil recovery. Investigations in the current study concluded that thin layers facilitates the optimum gravity drainage oil recovery even in the upper layers,

The optimized grid (50 × 30 × 30: 120 ft × 80 ft × 50 ft) recovered 98.4% at 9 PV_{CO2inj} (132 years) and 94% at 3 PV_{CO2inj} (40 years) incremental recoveries in the miscible process at the one-fifth lower oil production rate constraint. This higher recoveries lead to the use of the optimized grid in the rest of the simulations. These simulation studies neglected the diffusion effect in the homogeneous reservoir (k_v/k_h=1.0).

8.2.3 Effect of Miscibility Development

To facilitate the comparative analysis, final incremental recoveries (%) obtained in all the sensitivity simulation studies are presented in **Table 8-1** for the respective pore volumes of CO_2 injected. These final incremental recoveries are also plotted, as shown in **Figure 8-1** to schematically compare the results obtained in all the numerical simulation cases. No-diffusion case recoveries are depicted by '+' symbol, Diffusion case results are shown as '×' symbol, whereas the green triangles (Δ) represent the heterogeneity case recoveries.

Table 8-1: Summary of final incremental EOR in all the secondary and tertiary CO_2-assisted gravity drainage EOR methods

Type of reservoir	Process Description	Study property	Final Incremental EOR (%)	Pore Volumes of CO_2 injected	Production time/years
Homogeneous	Secondary miscible	No Diffusion	98.4 (94)	9 (3 PV)	132 (40)
		Diffusion	**100**	**1.45**	**24**
	Secondary immiscible	No Diffusion	96.63	8.9	132
		Diffusion	**95.54**	**3.53**	**53.5**
Heterogeneous	Secondary miscible	No Diffusion	95.5	3	132
		Diffusion	**97.8**	**3.2**	**91**
Homogeneous	*Tertiary* miscible	No Diffusion	97	8.75	132
		Diffusion	**94.83**	**2.6**	**36**
	Tertiary immiscible	No Diffusion	93	8.9	132
		Diffusion	**94.51**	**7.89**	**120**

Comparison of the final incremental EOR in **Table 8-1** and **Figure 8-1** shows that the final incremental oil recovery in 132 years of immiscible and miscible CO_2 injection ranges between 93 to 98.4% when diffusion effects are neglected. Cluster of final recoveries represented by '+' symbol in **Figure 8-1** indicates that 8.75 to 9 PV_{CO2inj} were required to be injected to achieve these final recoveries.

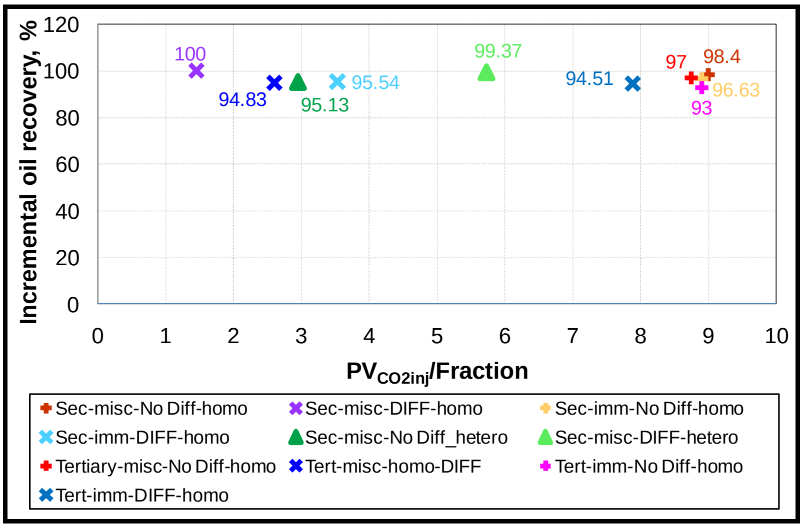

Figure 8-1: Summary of the final incremental EOR obtained in all the cases of immiscible and miscible - secondary / tertiary mode CO_2-assisted gravity drainage EOR Methods

Incremental oil recoveries (%) obtained in all of the no-diffusion sensitivity runs versus the respective pore volumes of CO_2 injected are plotted as shown in **Figure 8-2**. **Figure 8-2A** shows that the secondary and tertiary miscible processes recover 98.4% and 97 % incremental oil in the homogeneous reservoir (kv/kh=1.0). On the other hand, secondary and tertiary immiscible without diffusion methods yield 96.63 and 93% incremental oil recovery at 8.9 PV_{CO2inj}. These immiscible recoveries are 2 to 4% lower than the miscible case recoveries. Moreover, **Figure 8-2B** indicates that all of the four cases took 132 years to obtain these recoveries. These immiscible final recoveries look to approach closer towards the miscible incremental recoveries (no diffusion case) which are considerably higher than 90%. This Comparison demonstrates that the *miscibility generation may not be a pre-requisite criterion* for obtaining higher incremental oil recovery in the CO_2-assisted gravity drainage method, provided that the sufficient pore volumes of CO_2 are injected and the sufficient oil production times are allowed.

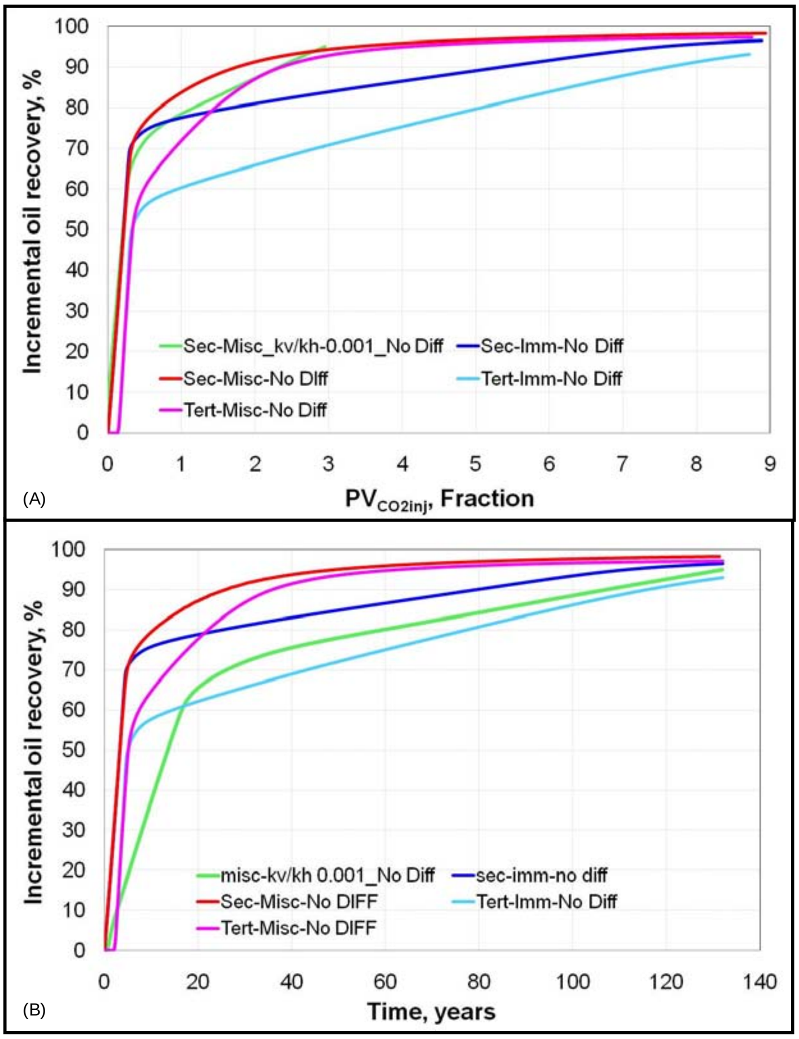

Figure 8-2: Final incremental EOR obtained in all the *no-diffusion* cases of immiscible and miscible - secondary / tertiary mode CO_2-assisted gravity drainage EOR Methods

Furthermore, comparative analysis of the incremental oil recoveries at 2.5 PV_{CO2inj} shows that the secondary miscible process yields near-perfect recoveries while tertiary miscible process recover 22.48% incremental recovery more than their immiscible counterparts. These results point out the *miscibility development hastens the CO_2-assisted gravity drainage oil recovery process thereby* enhancing the oil recovery optimization. It means that the mechanisms with which these recoveries are achieved are faster and yields higher recovery in miscible process than the immiscible process.

This hypothesis is supported by the results presented in the sections 6.1.2, 6.1.3 and 6.2.3. **Figure 6-7** and **Figure 6-20** demonstrated that the oil from the representative blocks (21, 20, 7) and (25, 14, 23) is produced under gravity drainage until CO_2 breakthrough. It continues to produce oil gradually after gas breakthrough through the gravity drainage driven oil film flow until it reduced to zero in the immiscible process. Moreover, the slow oil vaporization by the injection gas, CO_2, also contributed the incremental oil recovery (see **Figure 6-20C**).

On the other hand, the oil viscosity, gas saturation and oil saturation profiles in miscible process in the blocks (25,14, 6), (25,14, 7) and (25,14, 8) presented in **Figure 6-8, Figure 6-9** and **Figure 6-10** and in (25,14,23) point out that the oil swelling and gravity drainage are the main oil recovery mechanisms before CO_2 floodfront arrival. After CO_2 breakthrough, the increase in the oil viscosity along with the gas saturation suggested the oil vaporization of by CO_2. This mechanism especially in very light oil of 50 API is observed to be more pronounced. Comparison of the **Figure 6-7** and **Figure 6-20** in the base model shows that the miscible mechanisms yield complete oil recovery in 48 years earlier than the immiscible process. Similarly, **Figure 6-20** demonstrated that the miscible process mechanism of oil vaporization (extraction) provided complete recovery in 30 years than 124 years in the immiscible process mechanisms of the gravity drainage, oil film flow and slow vaporization. Even in the tertiary miscible mode, the oil vaporization by CO_2 is observe to hasten the CO_2-assisted gravity drainage oil recovery (see **Figure 6-30** and **Figure 6-32)** It is important to note here that the diffusion effects were neglected in this study.

8.2.4 Effect of Molecular Diffusion

Figure 8-1 and **Figure 8-3** represent the incremental oil recoveries in all the immiscible and miscible CO_2-assisted gravity drainage EOR methods in presence of the active diffusion phenomena. Final incremental oil recoveries with the active cross-phase diffusion yields near-perfect (100%) and 95.54% incremental oil recovery when 1.45 and 3.53 PV_{CO2inj} in the secondary miscible and immiscible process respectively. On the other hand, tertiary miscible and immiscible CO_2 injection process recovered 94.83 and 94.51% in 2.6 and 7.89 PV_{CO2inj}. Secondary and tertiary miscible process recoveries are achieved in 24 and 36 years respectively which is less than one-fifth and one-fourth time than the no diffusion case. of the PV_{CO2inj} in no-diffusion. Even in the heterogeneous reservoir (vertical permeability of 1.2 mD; k_v/k_h=0.001), the diffusion mechanism takes only about 3 PV to recover 97.38% incremental oil in 89 years. These results point out that the *molecular diffusion phenomenon further hastens the oil recovery process in both the miscible and immiscible CO_2-assisted gravity drainage EOR process*. This observation is augmented by the results presented in **Figure 6-27** (Section 6.4.1) in the form of the oil viscosity, gas saturation and the oil saturation changes occurred during the diffusion mode CO_2 flooding. Gravity drainage with the oil swelling due to the oil viscosity reduction is the oil recovery mechanism before CO_2 floodfront arrival. Later, the continuously increasing oil viscosity along with the rising gas saturation is the indicative of more effective oil vaporization through the active cross-phase diffusion phenomenon. Results presented in **Figure 6-26, Figure 6-28, Figure 6-29** and **Figure 6-33** further supports the diffusion induced hastening of the CO_2-assisted gravity drainage oil recovery.

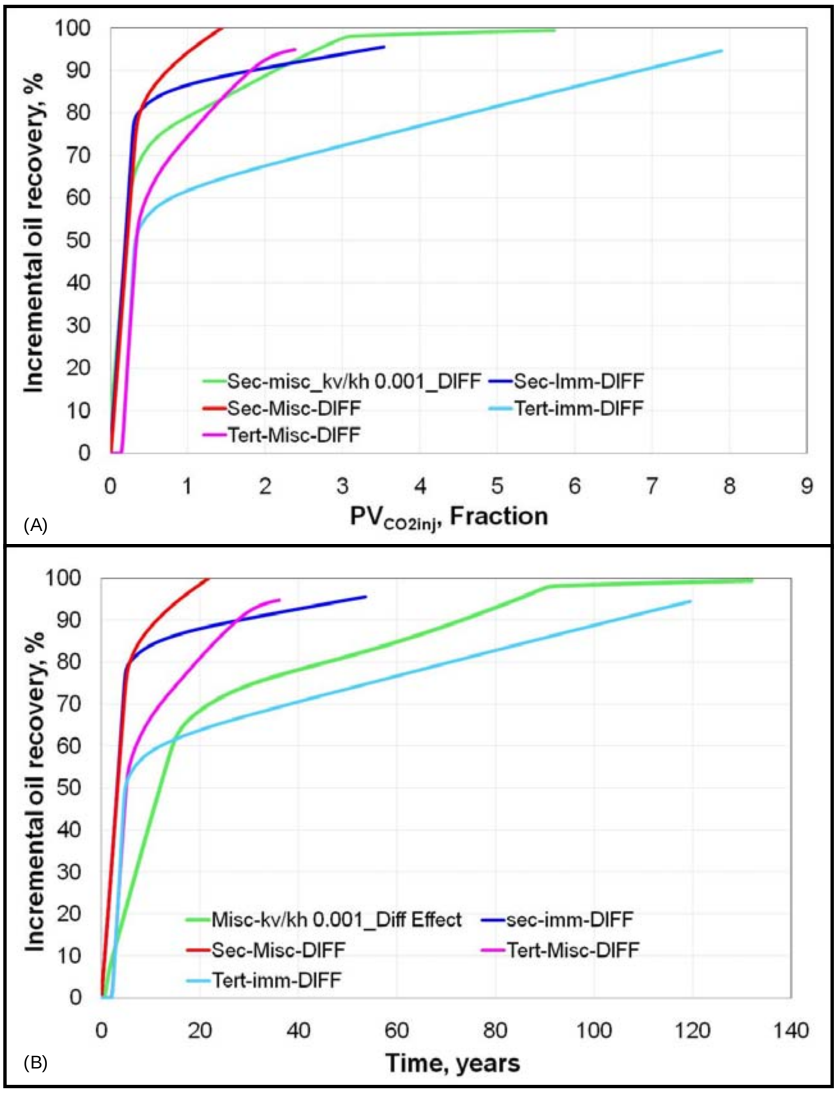

Figure 8-3: Final incremental EOR obtained in all the *diffusion* cases of immiscible and miscible - secondary / tertiary mode CO_2-assisted gravity drainage EOR Methods

8.2.5 Effect of Heterogeneity in Permeability and Porosity

Performance of the CO_2-assisted gravity drainage EOR method was investigated in a reservoir with vertical permeability of 1.2 mD (k_v/k_h=0.001). Secondary miscible process without diffusion in the heterogeneous (k_v = 1.2 mD) reservoir recovered 95.5% incremental oil at 3 PV_{CO2inj} in 132 years. Conversely, the cross phase diffusion mechanism yield 2% higher incremental recovery at 3.2 PV_{CO2inj} than the no-diffusion case in only 89 years thereby saving the operational costs of CO_2 injection and oil recovery operations. These studies concluded that the permeability heterogeneity (k_v variation in vertical and horizontal direction) does not incur negative impact on the final incremental oil recovery. Instead, it *improves oil recovery thereby reducing the number of pore volumes of CO_2 injected* (about 3 PV_{CO2inj} in this case) *and the operational time*.

Investigation regarding the heterogeneity in porosity wherein the porosity values of the reservoir under investigation is increasing from the injectors in the gas zone towards the horizontal producers at the bottom of the producing oil zone. Such field reservoirs are the over-turned faults wherein the virgin sediments having higher porosity are buried down under. Reservoir simulation studies conducted in this research showed that gravity drainage mechanism in such reservoirs would improve oil recovery performance compared to other reservoirs wherein the greater porosity heterogeneity exists within the gas and oil zones.

8.2.6 Effect of Mode of Gas Injection

Comparisons of incremental oil recoveries in the secondary and tertiary mode of CO_2 injection is carried out in this study in miscible as well as immiscible CO_2-assisted gravity drainage EOR method. **Figure 8-2 and Figure 8-4** shows that the miscible process in no-diffusion case recovered 98.4% (3PV) and 97% (8.75 PV) incremental oil in the secondary and tertiary mode of CO_2 injection. In order to provide the comparative analysis at 2.5 PV, the incremental oil recoveries are presented as shown in **Figure 8-5.** Even at 2.5 PV, these respective recoveries were 90.79 (in 38 years) and 93.23% (in 40 years)**.** Moreover, the diffusion case results (**Figure 8-3 and Figure 8-4**) deliver near-perfect and 94.83% recovery in only 1.45 and 2.6 PV over 26 and 36 years in the secondary and tertiary mode of CO_2 injection respectively. Even these recoveries above are very lucrative from the EOR point of view considering the incremental recoveries reported in the literature in the gravity drainage field projects as well as the WAG filed projects (9.4% average). Analysis of these incremental recoveries demonstrates that the *mode of gas injection has minimal effect on the miscible CO_2-assisted gravity drainage EOR process*.

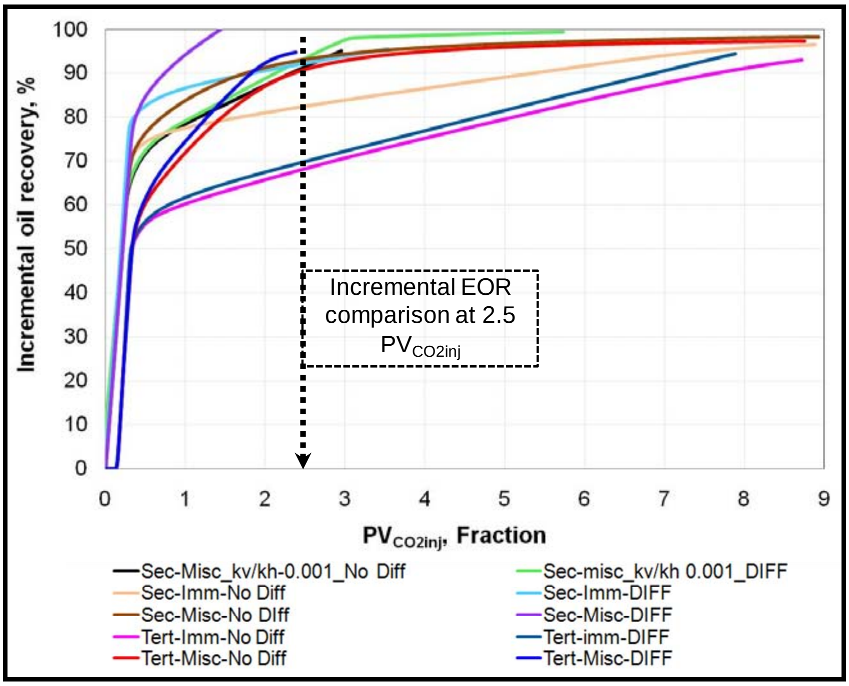

Figure 8-4: Incremental EOR (%) in all the *no-diffusion* and *no-diffusion* cases of CO_2-assisted gravity drainage EOR Methods

Immiscible CO_2 injection in the secondary and tertiary mode results in the 96.63% (8.9 PV over 132 years) and 93% (8.9 PV over 132 years) incremental oil recovery respectively (**Figure 8-3**) in the no-diffusion process. On the other hand, secondary and tertiary mode immiscible process recoveries in the active diffusion cases are 95.54% (3.53 PV in 53.5 years) and 94.51% (7.89 PV in 120 years). **Figure 8-5A** shows that the tertiary immiscible gravity drainage recovery is 14.23% lower than the secondary immiscible recovery in no-diffusion case. On the other hand, secondary mode diffusion case recovery provided 92.23% incremental recovery, which is 22.23% lower than the tertiary mode immiscible (70%) gravity drainage oil recovery. These results suggest that *the secondary mode immiscible CO_2 injection is highly effective in providing significant incremental benefits from the CO_2-asssited gravity drainage oil recovery point of view*.

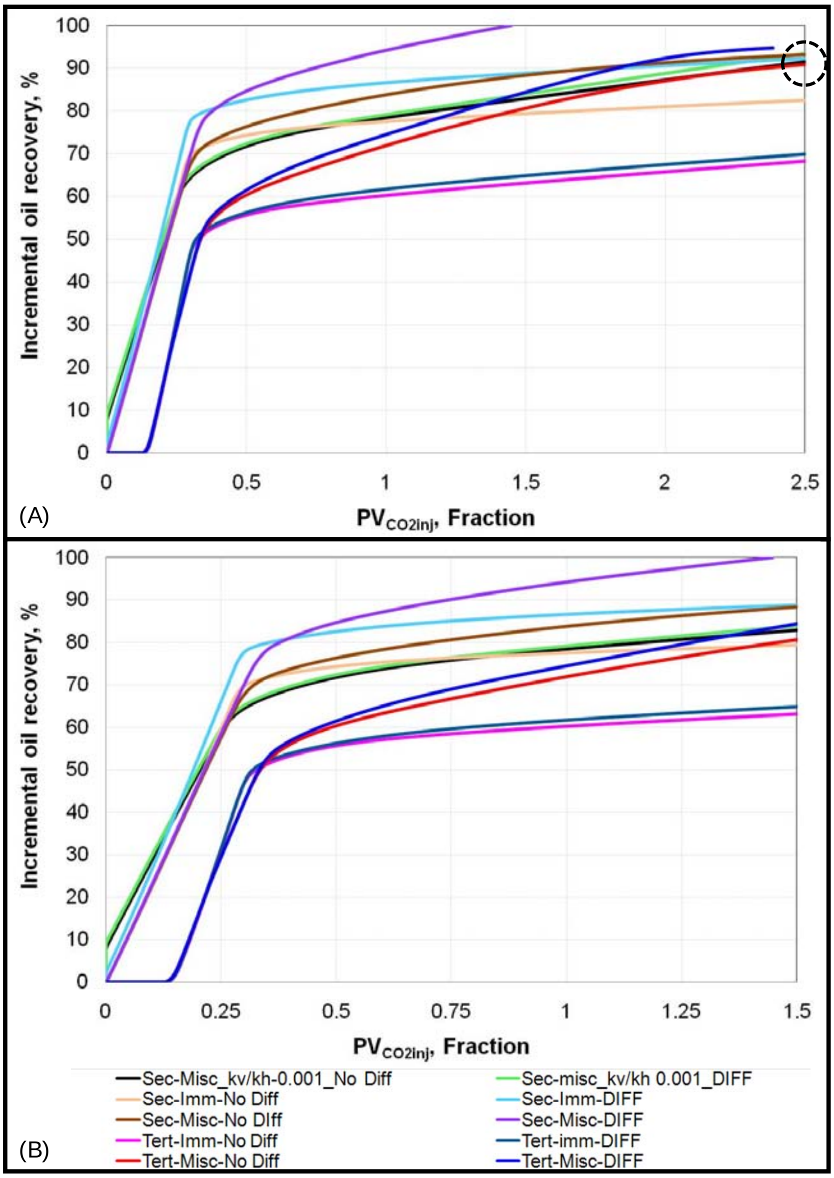

Figure 8-5: Incremental EOR (%) in all the cases of CO_2-assisted gravity drainage EOR Methods at (A) 2.5 PV$_{CO2inj}$ and (B) 1.5 PV$_{CO2inj}$

All the incremental oil recoveries obtained in this study are plotted at the maximum 2.5 and 1.5 PV$_{CO2inj}$ as shown in **Figure 8-5.** CO_2-assisted gravity drainage incremental oil recoveries at 2.5 PV$_{CO2inj}$ observed to be greater than 90.79%. Cluster of incremental recoveries in all the CO_2-assited gravity drainage EOR processes at 2.5 shows that *the secondary (both the miscible and immiscible) and the tertiary mode miscible processes yield higher incremental oil benefit than the tertiary mode immiscible CO_2-assisted gravity drainage EOR process*. Even at 1.5% PV$_{CO2inj}$, these recoveries are 15% higher in secondary (higher than 80%) than the tertiary mode (70%) gravity drainage oil recovery. These are still very attractive from the oil recovery point of view when compared with the gravity drainage recoveries reported in the literature (see section 2.3.6; **Table 2-6**) and the other conventional EOR methods of CGI and WAG. Nevertheless, the oil recovery optimization studies in this investigation show that the CO_2-assited gravity drainage EOR process clearly outperforms the other EOR methods with regards to the incremental recovery benefits.

8.3 Concluding Comment on the Oil Recovery Mechanisms

Results obtained in the reservoir simulation studies in both the immiscible and miscible CO_2-assisted gravity drainage EOR process clearly demonstrated the operational oil recovery mechanisms. Oil production occurred at the solution GOR in both the immiscible and miscible process with no injection gas breakthrough at the horizontal producing wells until the CO_2 floodfront arrival.

Very low reservoir pressure drop (less than 1psi/year) in immiscible process suggests that the conditions of no pressure gradient are prevalent in gas-zone behind the gas-oil contact (gas floodfront) during the entire CO_2 flooding operation. This satisfies the Cardwell and Parsons criteria (1949b) of free-fall gravity drainage mechanism. There could be a small pressure gradient across the gas-oil contact. Therefore, immiscible CO_2-assisted gravity drainage EOR process proceeds with the combination of these overall mechanisms: (i) Free gravity drainage behind the gas-oil interface, (ii) Buckley-Leverett type piston displacement in the oil zone, (iii) Forced gravity drainage at the gas-oil interface.

Immiscible process results point out that the density difference between oil and gas aids in the efficient drainage of oil under gravity effect (oil-film flow) signifying the free-fall gravity drainage of Cardwell and Parsons (1949b). This gravity drained oil from gas zone accumulates ahead of the gas floodfront to form an oil bank, which is produced immiscibly through Buckley-Leverett type displacement (1942).

Profile of changes in the oil viscosity, gas and oil saturations demonstrated that there exist the other micro-mechanisms that contribute the immiscible CO_2-assisted gravity drainage oil recovery. These include the oil swelling, extraction and/or vaporization of oil specifically by CO_2 and cross-phase diffusion.

In high pressure miscible process, the reservoir pressure drop was relatively higher, the maximum of 5 psi/year, compared to their immiscible counterparts. Moreover, the oil production occurred at solution GOR wherein second phase CO_2 does not compete with reservoir oil. It further suggests that there is a small pressure gradient across the gas-oil contact, by virtue of which the oil production is taking place. Oil zone is being produced by Buckley-Leverett type piston displacement, followed by an oil-CO_2 miscible zone. Gas breakthrough occurs when the leading edge of the miscible zone reaches the horizontal producing wells placed at the bottom of oil zone. At the same time, 5 psi/year reservoir pressure drop suggests that the reservoir pressure behind the CO_2-oil miscible zone is constant reminiscent of the free-fall gravity drainage of oil. Based on these observations, overall mechanisms in the miscible CO_2-assisted gravity drainage EOR process are: (i) Free gravity drainage behind the CO_2-oil miscible zone, (ii) Buckley-Leverett type piston displacement in the oil zone, (iii) Forced gravity drainage at the gas-oil interface.

Evaluation of the oil viscosity, gas and oil saturations during miscible CO_2-assisted gravity drainage oil recovery clearly demonstrate that the oil swelling contributes the gravity drainage mechanism before the gas floodfront arrival whereas the oil extraction and/or vaporization and the gravity drainage contribute the oil recovery. Molecular diffusion further hastens the CO_2-assisted gravity drainage oil recovery after the gas floodfront arrival.

In terms of the efficient mechanism that relatively provide earlier recovery is analysed based on the investigations pursued on 50 ^{o}API gravity reservoir in this study. Its decreasing order can be given as the molecular diffusion, oil extraction and/or vaporization, oil swelling, oil-film drainage under gravity effect. This order presented for both the immiscible and miscible CO_2-assisted gravity drainage EOR process can be effective tool to select the gravity drainage EOR process either of the immiscible or miscible one, thereby keeping in mind the process operational constraints.

8.4 Scaling and Sensitivity Analysis

Reservoir simulation studies conducted so far clearly pointed out the mechanistic multiphase parameters that are operational in the CO_2-assisted gravity drainage EOR process under investigation. Their relative dominance is identified though risk analysis. Interactions amongst them are further studied through Scaling and sensitivity analysis in two approaches: (1) Develop a new correlation using traditional dimensionless numbers encompassing the multiphase operational parameters and assess its application to CO_2-

assisted gravity drainage EOR process, and (2) Investigate the CO_2-assisted gravity drainage EOR process using the additional dimensionless groups that are not covered by a new correlation.

In order to develop a new correlation, the effects of Capillary, viscous and gravity forces on the immiscible and miscible CO_2-assisted gravity drainage oil recovery are first studied through the analysis of respective changes occurring in capillary number, gravity number and bond number. Inferences of the oil recovery profiles (%OOIP) in both the immiscible and miscible process concluded that the oil recovery performance improves with the reduction in capillary number, N_B (**Figure 7-2** and **Figure 7-3**), increase in the Bond number, N_B (**Figure 7-4** and **Figure 7-5**) and gravity number, N_G (**Figure 7-6** and **Figure 7-7**). Moreover, the viscosity increase improved the oil recovery. Additionally the density difference between the injection gas and the reservoir oil strongly drives gravity drainage process.

Current combination models presented by Kulkarni (2005) and Rostami (2009) were also used in this study to analyse their applicability. Kulkarni (2005) model represented the oil recovery is directly proportional the addition of capillary with the exclusion of the oil and gas viscosity parameters, which is in contrast with the findings in this investigation. Combination model presented by Rostami (2009) excluded the gravity number term and offered poor logarithmic correlation for CO_2-assisted gravity drainage EOR process. Based on the findings in this study and shortcomings of the published combination numbers, a new combination group is proposed.

New correlation, $N_{\text{Jadhawar and Sarma}}$, provided very good match of both the immiscible and miscible oil recovery obtained in the reservoir simulations in different porous media of 1200 mD, 120 mD and 1.2 mD and in the gravity drainage field projects (see section 7.2.5). The new combination dimensionless group provided reasonable accurate logarithmic correlation with oil recovery using the data of this PhD research and the field projects validation with very low data dispersion (**Figure 7-13** and **Figure 7-14**). Therefore it is concluded that the new correlation, $N_{\text{Jadhawar and Sarma,}}$ will be able to capture the important multiphase operational parameters successfully and predict the oil recovery with reasonable accuracy at difference scaling numbers, provided the data required for the calculation of dimensionless numbers is available.

Investigation of CO_2-assisted gravity drainage EOR process using additional dimensionless groups that are not covered by a new correlation, $N_{Jadhawar\ and\ Sarma}$ is carried out through the development of additional dimensionless groups. These are the injection rate based gravity number, pressure based gravity number, water-oil and gas-oil mobility ratio group, injection and producing pressure groups and residual oil saturation to gas and oil. Functional relationship between these scaling groups and their effect on the immiscible CO_2-assisted gravity drainage oil recovery is studied using the data of the reservoir simulations in 35 ^{o}API reservoir oil. Oil recovery behaviour for each of these dimensionless groups is represented in the form of dimensionless recovery (R_D) versus dimensionless time (t_D). Each of these scaling groups values are investigated by varying their values in one by one while keeping values of other scaling groups constant.

Comparison of the injection rate based gravity number with the pressure based gravity number concluded that pressure based gravity number is more appropriate to use in CO_2-assisted gravity drainage EOR process. Injection and producing pressure group results showed that the amount of oil displaced is inversely proportional to the injection and production well pressure (**Figure 7-19**). Dimensionless CO_2-assisted gravity drainage oil recovery is inversely proportional to the water-oil and gas-oil mobility ratio (**Figure 7-20 and Figure 7-21)**. Sensitivity analysis of the residual oil saturation to water (S_{orw}) and gas (S_{org}) concluded that lower the S_{orw} and S_{org} values, higher will be the dimensionless CO_2-assisted gravity drainage oil recovery (**Figure 7-22 and Figure 7-23)**. Inferences of the scaling and sensitivity analysis results lead to the conclusion these dimensionless groups must be include for the scaling of CO_2-assisted gravity drainage EOR process. Furthermore, the dimensionless recovery performance is validated through comparison of their values when parameters making up the dimensionless groups are changed so that the final values of all the scaling groups remain unchanged. Such a comparison presented in **Figure 7-24** in three sample reservoirs demonstrated that their dimensionless recovery performances agrees to each with just maximum of 10% variation until gas breakthrough.

Precisely, the dimensionless groups presented in this study are validated in two approaches:

(i) Oil recovery performance (%OOIP) through the new combination model, $N_{Jadhawar\ and\ Sarma}$, using the reservoir simulation data and the gravity drainage field projects; and then

(ii) Dimensionless recovery performance of three sample reservoirs using the additional dimensionless groups, by varying the values of parameters making up the dimensionless groups so that the final values of the scaling groups remain constant.

Based on the closely matched CO_2-assisted gravity drainage oil recovery performance, it is concluded that dimensionless groups presented in this study captures all the operational multiphase parameters to completely scale the CO_2-assisted gravity drainage EOR process.

9 CONCLUSIONS AND RECOMMMEDATIONS

In this Chapter, the conclusions drawn from findings of the reservoir simulation and the scaling and sensitivity investigations in CO_2-assisted gravity drainage EOR process are presented. In this work, the investigations are conducted over the 50 ^{o}API gravity reservoir-oil in studying the gravity drainage oil recovery performance. Such work has not been carried out previously. Based on the findings in this study, the scope for the future research work is also outlined at the end.

9.1 Conclusions

The results of the investigations conducted in this research work to accomplish the set PhD objectives led to the following conclusions.

1. The results of the investigations to study the effect of the injection well type showed that the type of CO_2 injection well (vertical versus horizontal) may not be a significant factor in the optimization of CO_2-assisted gravity drainage oil recovery. Instead, the horizontal wells might diminish CO_2-assisted gravity drainage oil recovery.

2. New hypothesis of the development of horizontal gas-oil interface by the regular well pattern (RWP) is introduced specifically for CO_2-assisted gravity drainage EOR process and verified in this study. It has been found that the oil production rate show near-vertical abrupt drop, especially in the immiscible flood, with the corresponding delay in CO_2 breakthrough. Analysis of the corresponding results in this study concludes that the regular well pattern (RWP) maintains gas-oil interface more horizontal than the irregular well pattern (IWP).

3. Well patterns play an important role in the formation of stable and horizontal gas-oil front without the occurrence of the CO_2-fingering, which in turn provide an effective CO_2-assisted oil gravity drainage rate.

4. Results of the well pattern studies also concluded that the regular well pattern is more effective in keeping the reservoir pressure drop to minimum, thereby promoting the CO_2-assisted gravity drainage mechanism and yielding higher oil recovery of

maximum 2.5%, compared to the irregular well pattern.

5. Studies regarding the effect of connate water saturation concluded that lower the connate water saturation, higher will the gravity drainage oil recovery.

6. Comparison of the immiscible and miscible CO_2-assisted gravity drainage oil recovery performance in the base model (50 × 30 × 10: 600 ft × 400 ft × 150 ft) suggests that the immiscible process dominated oil recovery before the CO_2 floodfront arrival whereas the miscible process outperform immiscible process after leading edge of the gas floodfront reaches the horizontal production wells.

7. Using the final incremental gravity drainage oil recoveries in the base model (50 × 30 × 10: 600 ft × 400 ft × 150 ft), a general map is proposed for CO_2-assisted gravity drainage EOR process to select a process between the immiscible and miscible. This can be used as a preliminary comparison tool.

8. If CO_2-EOR operations are constricted by the limits on GOR values (for example: 20000), then this “general selection criteria map” clearly indicate that the miscibility generation may not be a pre-requisite condition for the optimum CO_2-assisted gravity drainage oil recovery. In this case, very low injection of pore volumes of CO_2 may be required in the flooding process.

9. Grid size studies (x and y dimensions) has minimal effect on the CO_2-assisted gravity drainage oil recovery. Similar observation were put forward by Fassihi and Gillham (1993) wherein they varied only x-direction dimensions.

10. Thin layers in facilitates the optimum CO_2-assisted gravity drainage oil recovery even in the upper layers. The results found in this PhD research are significant because of the top to down progressing nature of the CO_2-assisted gravity drainage EOR process. These findings are in contrast with the results by Fassihi and Gillham (1993) and Ypma (1985).

11. Immiscible final incremental recoveries look to approach the miscible incremental recoveries (no diffusion case) which are considerably higher than 90%. This concludes that the miscibility generation may not be a pre-requisite criterion for obtaining higher incremental oil recovery in the CO_2-assisted gravity drainage method, provided that the sufficient pore volumes of CO_2 are injected and the

sufficient oil production times are allowed. Nevertheless, CO_2-assisted gravity drainage incremental oil recoveries are more than 8 times the reported incremental oil recovery in miscible WAG (average 9.4%).

12. Development of miscibility helps to enhance and hasten the CO_2-assisted gravity drainage oil recovery even in tertiary process. In contrast, tertiary immiscible process yields 22.48% lower recovery than their miscible counterparts. This further leads to another conclusion that the mechanisms with which the miscible recoveries are obtained are faster to yield higher recovery than the immiscible process. Inferences of the changes in oil viscosity, gas and oil saturation presented in this study proved that the oil swelling, extraction and/or oil vaporization mechanism in miscible process are faster than the oil film drainage under gravity mechanism along with the oil swelling and slower oil vaporization.

13. Molecular diffusion further hastens the oil recovery process in both the immiscible and miscible CO_2-assisted gravity drainage EOR process. Moreover, cross phase diffusion phenomenon, causing the transport of components based on their diffusivities, can eventually yield near-perfect recoveries.

14. Investigations of the effect of permeability heterogeneity in combination with the cross phase diffusion concluded that the variation in vertical permeability (k_v/k_h=1.0 and 0.001) improves CO_2-assisted gravity drainage oil recovery thereby reducing the number of pore volumes of CO_2 injected and the process operational time. Because of the top-down nature of process and operating mechanisms taking advantage of gravity and the cross-phase transport of oil components and the injection gas through diffusion, the permeability heterogeneity does not incur negative impact on the final incremental oil recovery.

15. Comparatively higher immiscible and miscible incremental oil recoveries in the secondary and tertiary mode of CO_2 injection lead to the conclusion that the mode of gas injection has minimal effect on the miscible CO_2-assisted gravity drainage EOR process.

16. Secondary mode immiscible CO_2 injection is highly effective in providing significant incremental benefits from the CO_2-asssited gravity drainage oil recovery point of view.

17. Secondary (both miscible and immiscible) and tertiary mode miscible processes provide higher incremental oil benefits than the tertiary mode immiscible CO_2-assisted gravity drainage EOR process.

18. In both the immiscible and miscible process, overall mechanisms of the CO_2-assisted gravity drainage oil recovery is combination of the forced gravity drainage at the gas-oil interface by virtue of the small pressure gradient, free gravity drainage in the gas zone behind the gas floodfront (gas-oil miscible zone in miscible case) and the Buckley Leverett piston type displacement in the oil zone where B-L theory, decline curve, continuity equation and the Darcy law are applicable.

19. New Dimensionless group, $N_{\text{Jadhawar and Sarma}}$, developed specifically for the CO_2-assisted gravity drainage EOR process is able to capture the important process operational multiphase parameters and is a useful tool for predicting oil recovery.

20. Based on the closely matched oil recovery performances (validation), it is concluded that dimensionless groups ($N_{\text{Jadhawar and Sarma}}$ and the additional groups) presented in this study provide sufficient pool of dimensionless groups that can captures all of the multiphase operational parameters affecting the CO_2-assisted gravity drainage oil recovery. It is therefore concluded that these scaled models can completely scale the CO_2-assisted gravity drainage EOR process.

21. Very high incremental oil recoveries in all the cases, and the inferences of the complete oil recovery from the various blocks of base and optimized model leads to a conclusion that the near-perfect or complete oil recovery is possible through the CO_2-assisted gravity drainage mechanism in either of the immiscible or miscible mode of CO_2 injection.

9.2 Further Recommendations

The reservoir simulations and scaling models study in this research suggests the following recommendations for further research:

1. To investigate the quantification of permanent CO_2 sequestration and storage through the CO_2-assisted gravity drainage EOR method.

2. Development of an analytical model quantifying the micro-mechanisms mainly oil film drainage and oil vaporization and cross-phase diffusion in the CO_2-assisted gravity drainage EOR process.
3. Testing and validation of the combination scaled model at the laboratory experimental conditions

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APPENDIX-A

Table A-I: PVT properties of 35 °API gravity reservoir oil

Pressure	GOR	B_o (p)sat	B_g	μ_o (p)sat	μ_g (p)sat	SWR	$B_{Solvent}$	$\mu_{Solvent}$
5766.1000	2830.6400	2.1641	0.0005	0.1416	0.0811	179.3020	0.0004	0.0738
4651.4700	1898.2400	1.8269	0.0006	0.1533	0.0535	170.0300	0.0004	0.0641
4161.1200	1365.5200	1.6130	0.0006	0.1707	0.0384	165.2480	0.0005	0.0593
3885.1000	1020.5800	1.4692	0.0007	0.1872	0.0295	162.3020	0.0005	0.0564
3703.3300	778.7650	1.3672	0.0008	0.1993	0.0236	160.2400	0.0005	0.0544
2400.0000	472.8700	1.2462	0.0012	0.2292	0.0178	140.6900	0.0007	0.0364
1700.0000	329.4060	1.1876	0.0017	0.2468	0.0155	121.9710	0.0012	0.0259
1500.0000	290.4520	1.1714	0.0019	0.2518	0.0150	114.2790	0.0014	0.0238
1250.0000	242.5420	1.1513	0.0023	0.2582	0.0144	102.6410	0.0019	0.0219
1000.0000	195.2970	1.1311	0.0029	0.2644	0.0138	88.4187	0.0025	0.0205
750.0000	148.3110	1.1107	0.0040	0.2704	0.0134	71.2808	0.0036	0.0196
550.0000	110.4890	1.0938	0.0055	0.2750	0.0130	55.2525	0.0051	0.0191
300.0000	61.0765	1.0708	0.0103	0.2801	0.0125	32.0450	0.0100	0.0186
150.0000	28.5117	1.0549	0.0208	0.2829	0.0120	16.3006	0.0208	0.0184
14.7000	0.0000	1.0382	0.2171	0.2863	0.0102	0.0000	0.2185	0.0182

Table A-II: End-point saturations used in the Stone-II model to generate relative permeability curves

Description	Value
SWCON - Endpoint Saturation: Connate Water	0.15
SWCRIT - Endpoint Saturation: Critical Water	0.3
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.18
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.2
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.05
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.1
SGCON - Endpoint Saturation: Connate Gas	0.05
SGCRIT - Endpoint Saturation: Critical Gas	0.05
KROCW - Kro at Connate Water	0.8
KRWIRO - Krw at Irreducible Oil	0.3
KRGCL - Krg at Connate Liquid	0.3
KROGCG - Krog at Connate Gas	0.8
Exponent for calculating Krw from KRWIRO	2
Exponent for calculating Krow from KROCW	2
Exponent for calculating Krog from KROGCG	2
Exponent for calculating Krg from KRGCL	2

APPENDIX-B

Calculation of the critical and stable gas injection rates using Dumore criterion (1964):

Data:

ρo, lb/ft^3 = 44.19637

$\rho_{CO2'}$ lb/ft^3 = 28.6

μo, cP = 0.196738

$\mu_{CO2,}$ cP = 0.056348

k , Darcy = 1.2

1. ***Critical floodfront velocity at which viscous fingering will occur and gas breakthrough will occur is***

$$u_{critical} = \frac{0.0439 * (\rho_{\mathrm{oil}} - \rho_{\mathrm{CO2}})\mathrm{lb/ft}^3 * \mathrm{k\ Darcy} * \mathrm{Sin}\alpha}{(\mu_{\mathrm{oil}} - \mu_{\mathrm{CO2}})cP}$$

$$u_{critical} = \frac{0.0439 * (44.19637 - 28.6)\mathrm{lb/ft}^3 * 1.2\ \mathrm{Darcy} * 1)}{(0.1957 - 0.0564)cP}$$

$$u_{critical} = 5.85\, ft / Day$$

2. ***Gas injection velocity at which the gas floodfront will be stable and no viscous fingering (gas breakthrough) occurs:***

$$M = \frac{\mu_{oil}}{\mu_{CO2}} = \frac{0.1957}{0.056348} = 3.491$$

$$\frac{u_{stable}}{u_{critical}} = \frac{\left(1 - \frac{1}{\mathrm{M}}\right)}{\ln(M)}$$

$$\frac{u_{stable}}{u_{critical}} = \frac{\left(1 - \frac{1}{3.491}\right)}{\ln(3.491)} = 0.570721$$

$$u_{stable} = 0.570721 * 5.85\, ft / Day = 3.34\, ft / Day$$

3. At what rate the CO_2 should be injected so that the oil drainage rates are lower than the $u_{critical}$ = 5.86 ft/day and u_{stable} = 3.34 ft/day ?

$$Maximum\ \mathrm{crtical}\ i_g = \frac{(5.85\, ft\,/\,Day)*(1319640\, ft^2)}{5.615*0.0005154} = 2.67E+09\ MMSCF\,/\,Day$$

$$Minimum\ \mathrm{critical}\ i_g = \frac{(5.85\, ft\,/\,Day)*(1055712\, ft^2)}{5.615*0.0005154} = 2.14E+09\ MMSCF\,/\,Day$$

$$Maximum\ stable\ i_g = \frac{(3.34\, ft\,/\,Day)*(1319640\, ft^2)}{5.615*0.0005154} = 1.52E+09\ MMSCF\,/\,Day$$

$$Minimum\ stable\ i_g = \frac{(3.34\, ft\,/\,Day)*(1055712\, ft^2)}{5.615*0.0005154} = 1.22E+09\ MMSCF\,/\,Day$$

APPENDIX-C

Calculation of the maximum and the minimum drainage rate: Reservoir simulation Studies

Optimized grid: (50 × 30 × 30: 120 × 80 × 50)

Well pattern: Regular well pattern

Gas injection rate, MMSCF/Day: Immiscible i_g = 7.30E+06, Miscible i_g = 1.03E+07

Maximum distance between the injection and the production wells, ft = 600

Minimum distance between the injection and production wells, ft = 480

Oil zone thickness (h), ft = 700

Max Area, ft^2 = Π*600*700 = 1319640; Min area, ft^2 = Π*480*700 = 1055712

Z @ 279 F and 2600 psi = 0.75; Z @ 279 F and 3600 psi = 0.72

T, ^oR = 740.67

Bottomhole injection rate @ 2615 psi (ft^3/D) = $V_{SC} * \dfrac{z*T}{P} * \dfrac{14.7(psia)}{520(R)}$

$$= (7.30E+06) * \frac{0.75*740.67}{2639.7} * \frac{14.7(psia)}{520(R)} = 4.34E+04 \text{ ft}^3\text{/D}$$

Bottomhole injection rate @ 3650 psi (ft^3/D) = $V_{SC} * \dfrac{z*T}{P} * \dfrac{14.7(psia)}{520(R)}$

$$= (1.03E+07) * \frac{0.72*740.67}{3664.7} * \frac{14.7(psia)}{520(R)} = 4.40E+04 \text{ ft}^3\text{/D}$$

Longest injection path:

Immiscible gravity drainage oil displacement velocity,

$= i_g / A = (4.34E+04)/1319640 = 0.0326$ ft/D

Miscible gravity drainage oil displacement velocity

$= i_g / A = (4.40E+04)/1319640 = 0.0334$ ft/D

Shortest injection path:

Immiscible gravity drainage oil displacement velocity,

$= i_g / A = (4.34E+04)/1055712 = 0.0326$ ft/D

Miscible gravity drainage oil displacement velocity

$= i_g / A = (4.40E+04)/1055712 = 0.0334$ ft/D

APPENDIX-D

Calculation of new combination number, $N_{Jadhawar\ and\ Sarma}$:

Following are the dimensionless numbers viz. Capillary number, Gravity number and Bond number calculated using data from the Oseberg field project, Norway.

Oseberg field properties:

ρ_{oil}, lb/ft^3 = 41.26
ρ_{gas}, lb/ft^3 = 13.55
μ_{oil}, cP = 0.4
μ_{gas}, cP = 0.023
$\sigma_{gas\text{-}oil}$, dyne/cm = 0.0031
Porosity, fraction = 0.27
Gas floodfront velocity = 0.17 ft/D
Characteristic length, *l* = SQRT((1*0.0000000000009869233)/0.2) = 2.2214E-06 m^2

Capillary Number (3865 psia & 215.6 ^{o}F) (Variation in Darcy velocity)

$$N_C = \frac{V(m/s)*\mu(Pa.S)}{\sigma(N/m)}$$

$$N_C = \frac{0.17(ft/D)*(0.0000035\ m/s/\text{ft/D})*0.023(\text{cP})*(0.001\,Pa.S/c\text{P})}{0.0031(\text{dyne/cm})*(1E-3N/m/dyne/cm)}$$

***N$_C$* = 4.54E-06**

Bond Number (3865 psia & 215.6 ^{o}F) (Variation in Grain Size)

$$N_B = \frac{\Delta\rho(kg/m^3)*g(m/s^2)*l^2(m^2)}{\sigma(N/m)}$$

N$_B$ =

$$\frac{(41.26-13.55)(lbm/ft^3)*(16.01846\ \text{kg/m}^3\text{/lbm/ft}^3)*(9.80665\ \text{m/s}^2)*((2.221E-06)^2\,\text{m}^2)}{0.0031(\text{dyne/cm})*(1E-3N/m/dyne/cm)}$$

N$_B$ = **0.006928986**

Gravity Number (3865 psia & 215.6 ^{o}F)

$$N_G = \frac{\Delta\rho(kg/m^3).g(m/s^2).k(m^2)}{\Delta\mu(Pa.S).u(m/s)}$$

N_G =

$$= \frac{(((41.26 - 13.55) * 16.01846) * (9.80665) * (1 * 0.0000000000009869233))}{(((0.4 - 0.023) * 0.001) * (0.1729 * 0.0000035))}$$

***N_G* = 7.45E+01**

New combination number, $\mathbf{N_{Jadhawar\ and\ Sarma}}$

$$N_{Jadhawar\ and\ Sarma} = \frac{(x)(N_G + N_B)}{(y)^a \, N_C{}^b} \quad (7.6)$$

where

$$x = \frac{\rho_{CO2}}{\rho_{Oil}}$$

$$y = \frac{1}{\mu_r}$$

$$\mu_r = \frac{\mu_{CO2}}{\mu_{Oil}}$$

$$a = b = 0.2$$

$\mathbf{N_{Jadhawar\ and\ Sarma}}$ $= \dfrac{(0.3284) * ((7.54E + 01) + (0.006928986))}{(1/0.0575)^{0.2} * (4.54E - 06)^{0.2}}$

$\mathbf{N_{Jadhawar\ and\ Sarma}}$ **= 3.51E-01**

VITA

Prashant S. Jadhawar was born in Pune, India. After completing his High school, he entered the Maharashtra Institute of Technology, affiliated to the University of Pune, India. He earned the degree of Bachelor of Engineering in petroleum Engineering in 1996. After his bachelor's degree, he worked in the same institute as a Lecturer in Petroleum Engineering and Co-ordinator of the postgraduate diploma course in Piping Design and Engineering from May 1997 to Sept 2003. During this tenure he also earned the Master of Engineering degree in Petroleum Engineering in 2000 with the 2nd rank in the University of Pune, India. Later he joined the graduate Petroleum Engineering program at Heriot-Watt University, UK in October 2003 to obtain the Master of Philosophy degree in Petroleum Engineering. In September 2006, he commenced the PhD program in Petroleum Engineering with the Santos postgraduate scholarship at the Australian School of Petroleum, University of Adelaide, Australia.