# MODELING GRAVITY SEGREGATION IN STRATIFIED AND DIPPING RESERVOIR OF VOLATILE OIL

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***ABSTRACTS***

*In this paper, we investigate gravity segregation in stratified and dipping reservoir of volatile oil under gas injection. A new efficient compositional simulation approach was used in this study to investigate the influence of gravity segregation and their magnitude in the case of gas injection into a volatile oil reservoir. The results show that in stratified and dipping reservoirs where the permeability decreases with depth, smaller the vertical to horizontal permeability ratio, lesser is the effect of gravity segregation, better is the sweep efficiency and hence better is the recovery. In the case of increasing permeability with depth in stratified dipping reservoirs, an up-dip gas injection into a volatile oil reservoir was found to be a favourable condition in term of recovery. Gravity forces have a considerable effect on volatile oil recovery via gas injection and the need for determining not only the fluid characteristics but also the reservoir heterogeneities was significant.*

***Key words**: compositional, equation of state, gravity segregation, volatile*

## I. INTRODUCTION

The volumetric sweepout during miscible and immiscible displacement is always less than 100% because of (Syahrial, 1997):

- permeability stratification,
- viscous fingering,
- gravity segregation,
- incomplete areal sweepout.

In the case of miscible displacement, the hydrocarbon solvents are typically both less viscous and less dense than reservoir oils. In horizontal reservoirs, gravity segregation due to density difference between injected fluid and the in situ fluid decreases vertical sweepout resulting in early breakthrough. On the other hand, the presence of gravity segregation in the dipping reservoir can improve sweepout and displacement efficiency. This can be attained by injecting the solvent up-dip and producing the reservoir at a rate low enough for gravity to keep the less dense solvent segregated from oil. In this way it is also possible to suppress fingers of solvent as they try to form. Therefore, if gravity segregation is properly handled the recoveries can be very high. For example, the Mbede Field in Nigeria showed that the final recovery factor ranges between 52% and 72% (Siti *et al*., 1992).

Spivak (1974) proposed a correlation for vertical sweepout at breakthrough for immiscible displacement and accounted for the influence of vertical permeability. Gardner *et al.*, (1962) observed the gravity segregation of miscible fluids in linear model. Generally, increasing gravity segregation can be found with:

- increasing permeability (either horizontal or vertical),
- increasing density difference,
- increasing mobility ratio,
- decreasing production rates.

In this study, a compositional simulation approach will be used to investigate the factors that influence gravity segregation and the magnitude of gravity effects in the case of dry gas injection into a range of

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

volatile oil reservoir. A stratified and dipping reservoir with constant and with spatially variable fluid compositions was chosen in this study. The composition of the production stream will be monitored in view of gravity segregation to explore the ways of maximizing recovery. By knowing the factors and the magnitude of the influence of gravity segregation, design considerations of the injection fluid into reservoir fluid can be properly accounted for.

## II. COMPOSITIONAL SIMULATION FOR VOLATILE OIL

Reservoir processes that require compositional modeling can be divided into two major types. The first type is depletion and/or cycling of volatile oil and gas condensate reservoirs. The second type is miscible flooding with first contact and multiple-contact-miscibility generated in situ. The development of compositional simulators can be classified into three categories. The first category concerns with the new formulations and efficient solution schemes for the mass conservation equations. In this category the formulations are divided into two basic schemes, namely IMPES and fully implicit schemes. The primary difference between these two schemes is in the treatment of the flow coefficient. The second category concerns with the efficiency of the phase equilibrium calculation schemes. In this category, the formulation is differenced whether or not they use the Equations of State for phase equilibrium and property calculations. The last category concerns the representations of physical phenomena, such as the effect of interfacial tension to the shape of relative permeability curves.

Several formulations which became the bases for the current state-of-the-art compositional simulation procedures have been proposed. These include two fully implicit formulations (Coats, 1980; Chien *et al.*, 1985), a sequential semi-implicit formulation (Watts, 1983), an adaptive implicit scheme (Collins *et al.*, 1992), three IMPES formulations (Kazemi *et al.*, 1978; Nghiem *et al.*, 1981; Acs *et al.*, 1985) and two formulations which solve for pressure and composition simultaneously, but use explicit flow coefficients (Fussell & Fussell, 1979; Young & Stephenson, 1983). Also, the other recent formulations that are essentially similar to these formulations have been commented on (e.g., Guehria *et al.*, 1990; Guehria *et al.*, 1991; Quandalle & Savary, 1989; Branco & Rodriguez, 1994; Rodriguez & Bonet, 1994; Rodriguez, Galindo-Nava & Guzman, 1994).

The IMPES appears to be the cheapest simulation alternative. This is because only one equation per grid block is solved (the pressure equation). In terms of physics, however, there is an important inconsistency in that the fluid is transported in the porous media by using current pressure differences and old time level transmissibilities. Hence, the velocity terms contain temporal inconsistencies. Fully implicit simulation approaches may seem to be computationally expensive per time step but due to their unconditionally stable nature, they can solve the most complex problems with fewer iterations and at a lower overall computational cost than IMPES scheme. However, the computer memory and CPU time required for the fully implicit methods are their major disadvantages.

In general, the IMPES is inherently unstable and the fully implicit can overkill the problem computationally. To realise the problems, it is therefore intended to propose a new formulation in order to minimize the cost of the computational simulation while maintaining the thermodynamic consistency of the prediction. The formulation must be able to model recovery from volatile oil reservoirs in the presence of heterogeneity under different recovery mechanism.

The new formulation employed the following finite difference equations as follows:

- Water equation:

$$\Delta\left[T_w\,\Delta\Phi_w\right]+\left(\xi_w\,q_w\right)=\frac{V_r}{\Delta t}\left[\left(\phi\,\xi_w\,S_w\right)^{n+1}-\left(\phi\,\xi_w\,S_w\right)^{n}\right], \qquad (1)$$

- Oil equation:

$$\Delta\left[T_o\,\Delta\Phi_o\right]+\left(\xi_o\,q_o\right)=\frac{V_r}{\Delta t}\left[\left(\phi\,\xi_o\,S_o\right)^{n+1}-\left(\phi\,\xi_o\,S_o\right)^{n}\right], \qquad (2)$$

- Gas equation:

$$\Delta\left[T_g\,\Delta\Phi_g\right]+\left(\xi_g\,q_g\right)=\frac{V_r}{\Delta t}\left[\left(\phi\,\xi_g\,S_g\right)^{n+1}-\left(\phi\,\xi_g\,S_g\right)^{n}\right], \qquad (3)$$

where transmissibility term $T_l$ in the x-direction,

$$T_l=\left(\frac{k\,A}{\Delta x}\right)\left(\frac{k_{rl}}{\mu_l}\xi_l\right), \quad l=o,\,g,\,w$$

In the above equation, $l$

$\lambda$ = $(k\,k_r/\mu)$ = phase mobility,

$\Phi$ = phase potential,

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

$\phi$ = porosity,
$\xi$ = molar density,
$S$ = phase saturation,
$x_i$ = mole fraction of component $i$ in the liquid phase,
$y_i$ = mole fraction of component $i$ in the vapour phase,
$z_i$ = total mole fraction of component $i$,
$K_i$ = equilibrium ration of component $i$,
$q_i$ = injection or production rate of component $i$.

The above equations are highly non-linear and analytical solutions are not possible. Consequently, numerical methods are required. To implement numerical techniques, however, the flow equations must be linearised and discretized by applying a finite difference scheme using backward difference in time and central difference in space (Peaceman, 1967). The results of discretisation leads to the system of equations in matrix form. This particular matrix form can be solved in each Newtonian iteration by either direct, or iterative methods in order to obtain the required changes in pressure and saturation.

The new formulation has an implicit equation for the oil-phase pressure and water saturation, an explicit equation for the hydrocarbon saturation, and explicit equation for the overall composition of each hydrocarbon component that satisfies thermodynamic equilibrium. The formulation uses an Equation of State for phase equilibrium and property calculations. Interfacial tension effects are included in the formulation to characterise the thermodynamically dynamic nature of the relative permeability. A two-dimensional relative permeability algorithm is included which handles lumped hydrocarbon phase as well as individual phase flows.

For each grid block two equations are required, namely total hydrocarbon and water-phase flow equations. The new compositional simulation approach is validated through analytical and other numerical methods. It was demonstrated in the previous publications that the results are compared favourably with analytical techniques and published numerical results (Syahrial & Daltaban, 1998; Syahrial & Daltaban, 1998; Syahrial 2010). They also confirm that the proposed codified formulation is unconditionally stable and it is as stable as fully compositional model yet the computational cost reduction was substantial.

## III. GRAVITY SEGREGATION IN STRATIFIED AND DIPPING RESERVOIR

After validating against analytical and numerical methods, the new compositional simulation approach is fully implemented to investigate the influence of gravity segregation and their magnitude in the case of gas injection into a volatile oil reservoir. A two-dimensional studies in which flow is permitted in only the horizontal and vertical directions is discussed. A stratified and dipping reservoir is used to illustrate the effect of gravity segregation on the oil recovery in the case of gas injection into volatile oil reservoirs. Well production performance, gas saturation distribution and the composition of the production stream will be monitored in view of gravity segregation in order to explore the ways of maximising recovery. By knowing the factors and the magnitude of the influence of gravity segregation, design considerations of the injection fluid into reservoir fluid can be properly evaluated.

A stratified reservoir with a dip of 8 degrees (from the horizontal) is a two-dimensional cross-section reservoirs. Horizontal permeability and porosity decrease with depth for each layer as listed in Table 1.

**Table 1**
**Model Data Used for Stratified Reservoir Study**

| Layer | Permeability (mD) | Porosity (frac.) |
|---|---|---|
| 1 | 900 | 0.178 |
| 2 | 800 | 0.176 |
| 3 | 700 | 0.173 |
| 4 | 600 | 0.172 |
| 5 | 500 | 0.168 |
| 6 | 400 | 0.166 |
| 7 | 300 | 0.162 |
| 8 | 200 | 0.157 |
| 9 | 150 | 0.155 |
| 10 | 100 | 0.150 |
| 11 | 80 | 0.147 |
| 12 | 70 | 0.145 |
| 13 | 60 | 0.142 |
| 14 | 50 | 0.137 |
| 15 | 40 | 0.135 |
| 16 | 30 | 0.132 |
| 17 | 25 | 0.127 |
| 18 | 20 | 0.125 |
| 19 | 15 | 0.122 |
| 20 | 10 | 0.116 |

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

The length of the reservoir is 3000 ft, width is 50 ft and the thickness of the pay zone is 100 ft. Initial reservoir pressure at the datum is 2800 psia with 20% water and 80% oil saturations yielding 0.324 MMBBL of hydrocarbon pore volume. Initial oil-in-place, calculated by flashing the oil at stock-tank conditions of 14.69 psia and 60°F is 208 MSTB and stock-tank GOR is 922 SCF/STB. Table 2 shows the other relevant data of this study.

The fluid used in this study is that of OIL-6 (Coats & Smart, 1982) and Table 3 shows the composition and properties of that fluid. The fluid data exhibits bubble point pressure of 2733 psia and the oil density is 36.9 lb/ft$^3$.

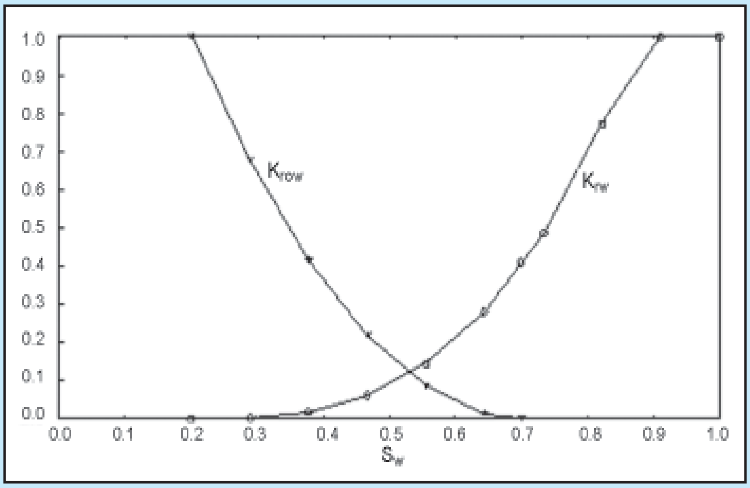


**Figure 1**
**Water-oil Relative Permeability Curves**

**Table 2**
**Data Used for Cross-Sectional Studies**

| Property | Field Units | SI Units |
|---|---|---|
| Grid System | 40x1x20 | 40x1x20 |
| Reservoir Length, $L$ | 3000 ft | 914.40 m |
| Reservoir Width, $w$ | 50 ft | 15.24 m |
| Thickness of the Pay Zone, $h$ | 100 ft | 30.48 m |
| Area of Cross-Section, $A$ | 5000 ft$^2$ | 464.52 m$^2$ |
| Dip Angle, $\theta$ | 0 | 0 |
| Horizontal Permeability, $k_h$ | 200 mD | 1.97x10$^{-13}$ m$^2$ |
| Porosity, f | 15% | 15% |
| Connate Water Saturation, $S_{wc}$ | 20% | 20% |
| Residual Oil Saturation, $S_{or}$ | 30% | 30% |
| Residual Gas Saturation, $S_{gr}$ | 5% | 5% |
| Initial Oil Saturation, $S_{oi}$ | 80% | 80% |
| Initail Gas Saturation, $S_{gi}$ | 0% | 0% |
| Initial Water Saturation, $S_{wi}$ | 20% | 20% |
| Initial Reservoir Pressure at Datum, $P_i$ | 2800.0 psia | 19.31 Mpa |
| Datum | 8500 ft | 2591 m |
| Reservoir Temperature, $T_r$ | 234°F | 112.2°C |
| Production Point, Grid Block No. | 1 | 1 |
| Injection Point, Grid Block No. | 40 | 40 |
| Rock Compressibility, $c_r$ | 4x10$^{-6}$ psi$^{-1}$ | 5.80x10$^{-7}$ kPa$^{-1}$ |
| Water Compressibility, $c_w$ | 3x10$^{-6}$ psi$^{-1}$ | 4.35x10$^{-7}$ kPa$^{-1}$ |

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

The relative permeability curves are shown in Figures 1 and 2. The reservoir domain is discretised by 40´20 grid blocks with a production well and a injector well at the extremas. Total number of active grid blocks is 800 and each gridblock contains 401 RBBL of hydrocarbon pore volume. It was assumed that production and injection wells penetrate all layers with oil production rate of 200 STB/Day and Minimum bottom hole pressure of 2000 psia. Down-dip production well with an oil rate of 200 STB/Day penetrates all layers and up-dip gas injection with the composition listed in Table 4 is used as the gas cycling processes. In this section the effect of permeable zone ordering and $k_v/k_h$ ratios on the final oil recovery are examined.

## A. Effect of Decreasing Permeability with Depth on Gravity Segregation

The effect of vertical permeability on gravity segregation in stratified and dipping reservoirs is investigated. Reservoir permeability is considered to decrease with depth. This is a typical of a deltaic bar deposits where both permeability and porosity are decreasing with depth. The detailed shapes are based on energy for sorting sedi-

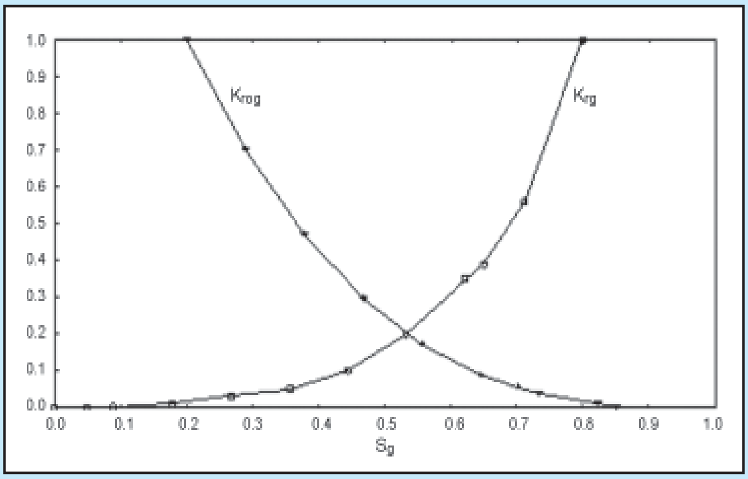


**Figure 2**
**Gas-oil Relative Permeability Curves**

**Table 3**
**Fluid Compositions and Properties at Reservoir Conditions**

| Component | Mole Frac. | $T_c$ (°F) | $p_c$ (psia) | $Z_c$ | MW | w | $P_{ch}$ |
|---|---|---|---|---|---|---|---|
| $CO_2$ | 0.0103 | 88.79 | 1071.33 | 0.2741 | 44.01 | 0.225 | 78.0 |
| $N_2$ | 0.0055 | -232.51 | 492.31 | 0.2912 | 28.01 | 0.040 | 41.0 |
| $C_1$ | 0.3647 | -116.59 | 667.78 | 0.2847 | 16.04 | 0.013 | 77.0 |
| $C_2$ | 0.0933 | 90.10 | 708.34 | 0.2846 | 30.07 | 0.099 | 108.0 |
| $C_3$ | 0.0885 | 205.97 | 618.70 | 0.2775 | 44.10 | 0.152 | 150.3 |
| $C_4$ | 0.0600 | 295.43 | 543.45 | 0.2772 | 58.12 | 0.196 | 187.2 |
| $C_5$ | 0.0378 | 378.95 | 487.17 | 0.2688 | 72.15 | 0.241 | 228.9 |
| $C_6$ | 0.0356 | 461.93 | 484.38 | 0.2754 | 84.00 | 0.250 | 271.0 |
| $C_7^+$ | 0.3043 | 836.63 | 266.33 | 0.2398 | 200.00 | 0.648 | 520.0 |

**Table 4**
**Composition of the Dry Injection Gas**

| *Dry Gas* | $C_1$ | $C_2$ | $C_3$ | $C_4$ | $C_5$ | $C_6$ | $C_7^+$ |
|---|---|---|---|---|---|---|---|
| **Mole Frac.** | 0.70 | 0.01 | 0.01 | 0.03 | 0.01 | 0.01 | 0.23 |

**LEMIGAS SCIENTIFIC CONTRIBUTIONS**
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

ments and results from consideration of depositional flow regimes, tidal range and current directions (Archer & Wall, 1986).

Three different ratios of vertical to horizontal permeability are used in modelling up-dip lean gas injection into volatile oil reservoir with $k_v/k_h$: 1.0, 0.1 and 0.01. The depletion processes was modelled with ratio of vertical to horizontal permeability of 0.1. The reservoir pressure is allowed to drop below bubble point to assess the evaporation effects.

Figures 3 and 4 present the production well performance after 1050 days of gas injection. Unlike homogeneous anisotropic and horizontal models discussed in the previous publication (Syahrial, 1997), there is a substantial recovery drop in the stratified case. This is due to the presence of higher permeability layers at the top of the reservoir which dominate the gas flow and cause early gas breakthrough, and stabilised gas profile distribution. After 1050 days, the oil recoveries are 51%, 59% and 60% respectively for $k_v/k_h$ : 1.0, 0.1 and 0.01, whereas the depletion process with $k_v/k_h$ of 0.1 is 16%. It is also apparent that the smaller the vertical to horizontal permeability ratio, the lesser is the effect of gravity segregation, better is the sweep efficiency and hence better is the recovery.

### B. Effect of Increasing Permeability with Depth on Gravity Segregation

Using the permeability and porosity data listed in Table 1, but with layer ordering reversed (with layer 1 having the smallest permeability and layer 20 having the highest permeability). This is a typical of a deltaic channel deposits where both permeability and porosity are in-

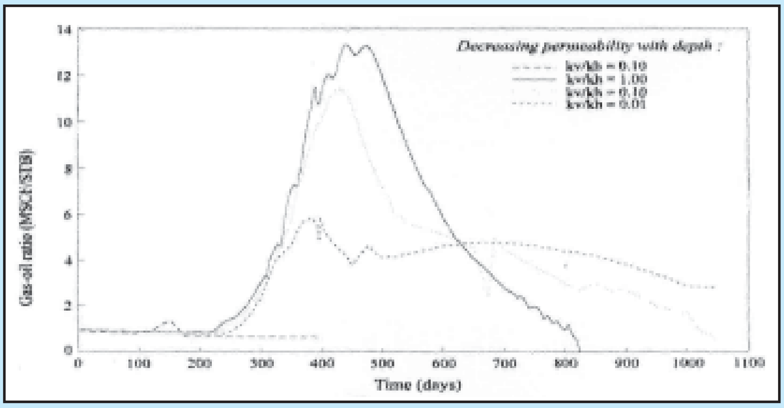


**Figure 3**
**GOR vs Time in a Dipping Reservoir with Decreasing Permeability**

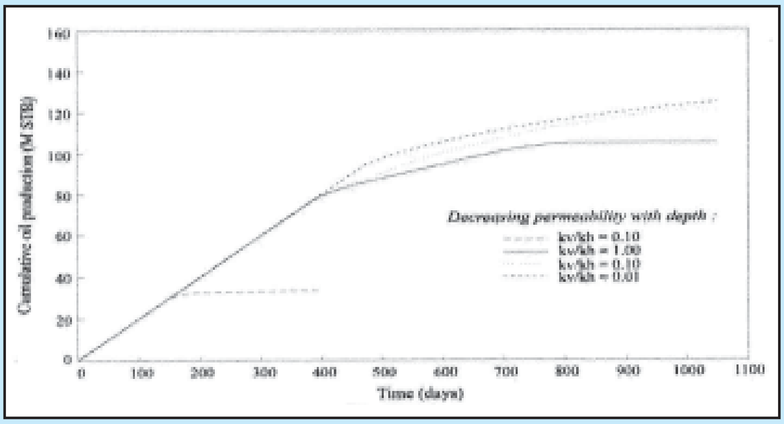


**Figure 4**
**Np vs Time in a Dipping Reservoir with Decreasing Permeability**

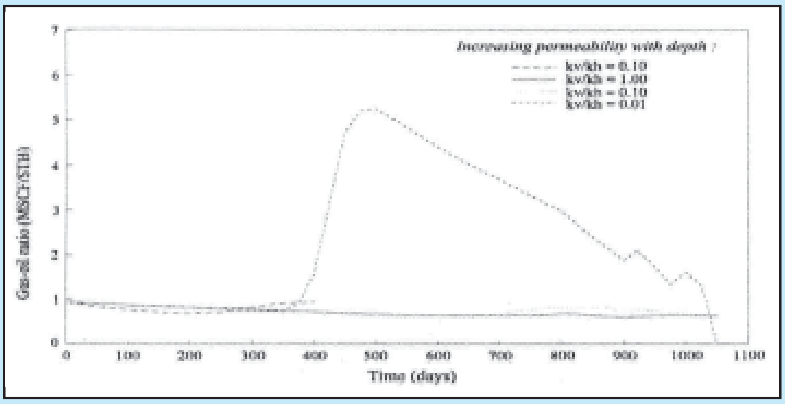


**Figure 5**
**GOR vs Time in a Dipping Reservoir with Increasing Permeability**

**LEMIGAS SCIENTIFIC CONTRIBUTIONS**
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

creasing with depth. In this typical reservoir, the coarser particles settle first and they are followed by gradual thinning in the grain sizes and the deposition progresses. It is related to the strength of the available energy. Permeability is related to the grain sizes and the greater of the grain size, the greater the permeability. Since the grain size becomes coarser with depth, the permeability increases as well.

Figures 5 and 6 present the production well performance after 1050 days of gas injection. Unlike the previous model, effect of vertical permeability in stratified case with permeability increasing with depth result in increased oil recovery. After 1050 days of injection, oil recovery for $k_v/k_h$ : 1.0, 0.1 and 0.01 are 69%, 68% and 68% respectively, whereas depletion process with $k_v/k_h$ of 0.1 was found to be 18%. It is also evident that the vertical permeability ratio does not alter the overall recovery significantly. This is because of the relatively high rates used. The gravity effects would be more pronounced if the flow rates were small enough to enhance segregation. In general, having the reservoir model with increasing permeability with depth is more preferable than the model with decreasing permeability, in term of final recovery factor.

Increasing permeability with depth is a favourable condition for the up-dip gas injection into a volatile oil reservoir. Figure 7 shows the gas saturation distribution of the decreasing permeability model after 400 days, whereas Figure 8 shows the model with increasing permeability. It can be seen that the decreasing permeability model was dominated by gas override. For $k_v/k_h$ of 0.1, the increasing permeability model improved the recovery factor

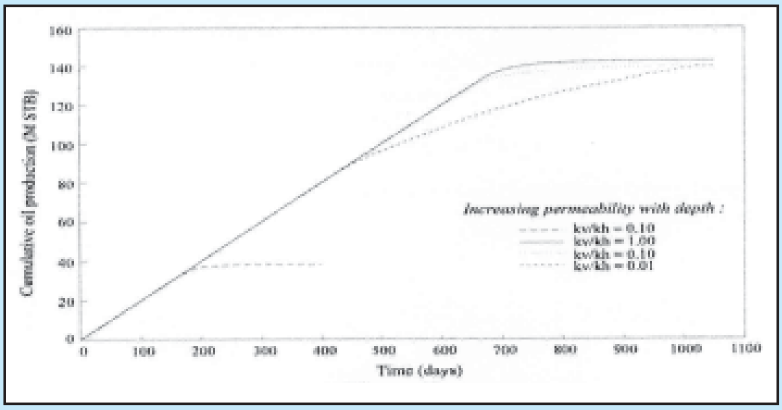


**Figure 6**
**Np vs Time in a Dipping Reservoir with Increasing Permeability**

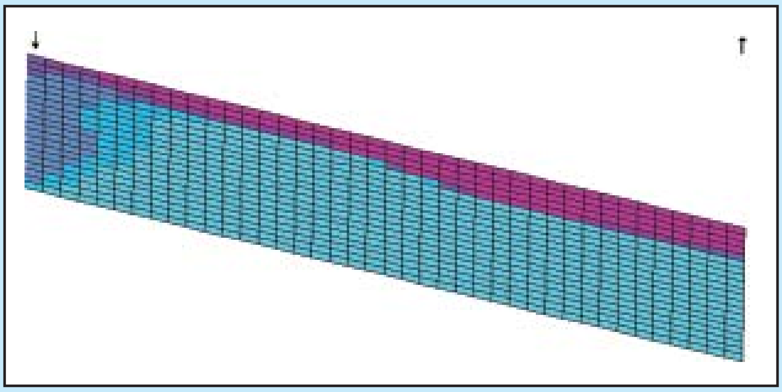

**Figure 7**
**Gas Saturation Distribution with Decreasing Permeability**

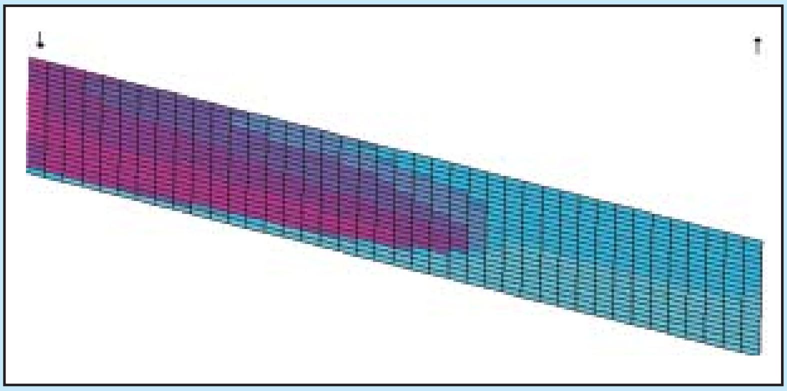

**Figure 8**
**Gas Saturation Distribution with Increasing Permeability**

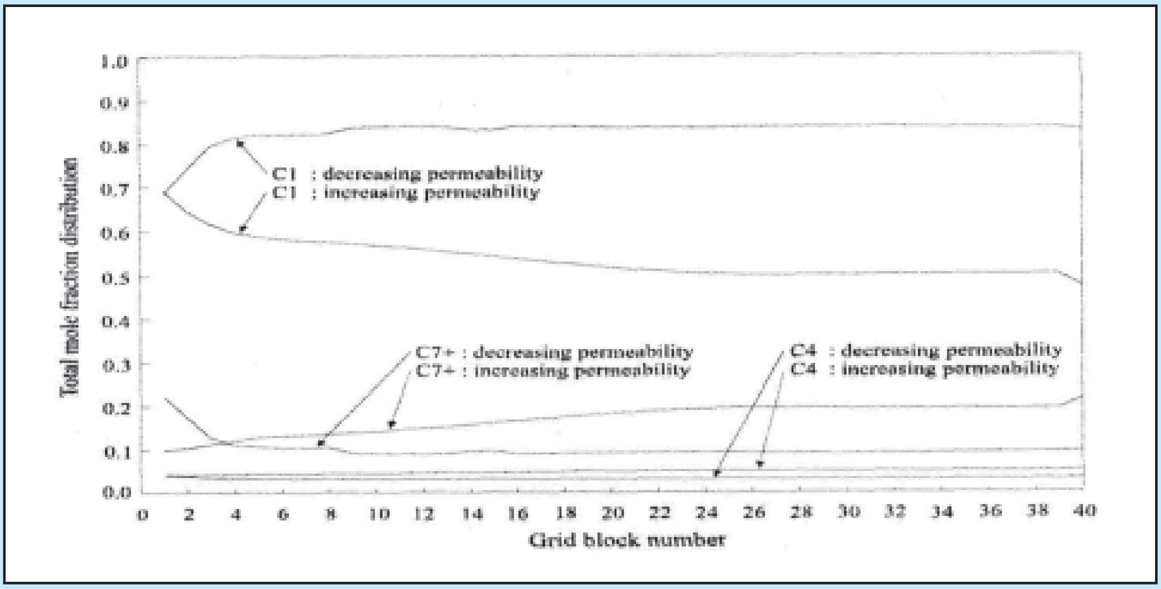


**Figure 9**
**Total Mole Fraction after 500 days at the Uppermost Layer**

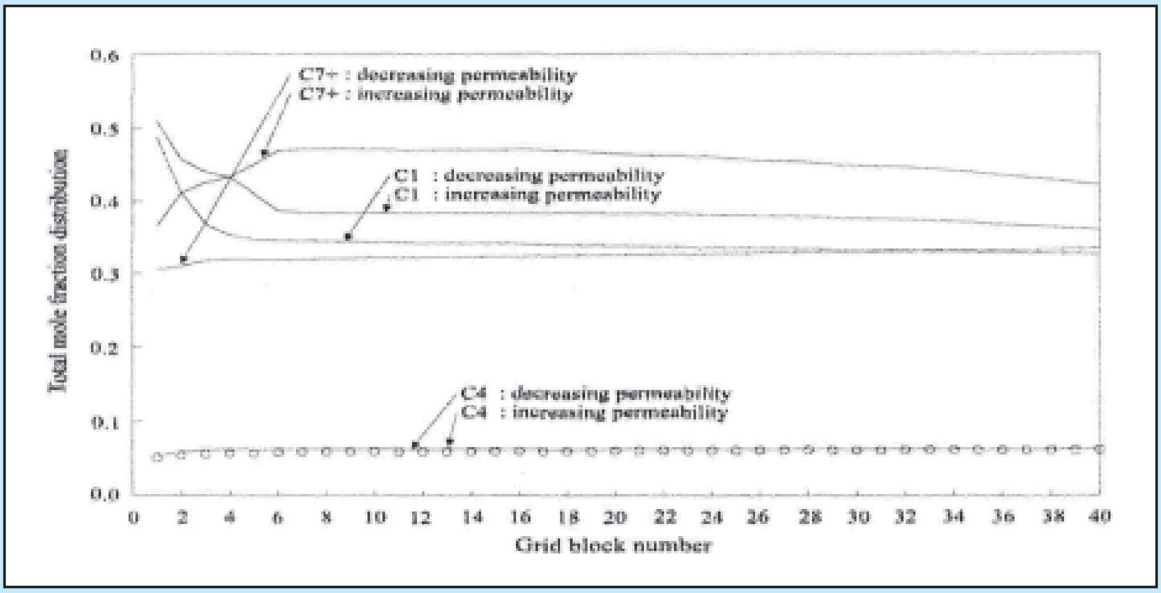


**Figure 10**
**Total Mole Fraction after 500 days at the Bottom Layer**

by 9% from 59% obtained from the decreasing permeability model.

Figures 9 and 10 illustrate the total mole fraction distribution of components at top and bottom layers after 500 days of gas injection. It can be seen that the total mole fraction of Methane was decreasing from injection well to production well, hence increasing the heavy component fraction in the production well in the upper layers for the increasing permeability model. Meanwhile, the decreasing permeability

LEMIGAS SCIENTIFIC CONTRIBUTIONS
VOL. 33. NO. 3, DECEMBER 2010 : 188 - 197

model showed an increase of Methane fraction in the producing well.

## IV. CONCLUSIONS

1. Gravity forces have a considerable effect on volatile oil recovery via gas injection and the need for determining not only the fluid characteristics but also the reservoir heterogeneities was significant.
2. In stratified, dipping reservoirs where the permeability decreases with depth, smaller the vertical to horizontal permeability ratio, lesser is the effect of gravity segregation, better is the sweep efficiency and hence better is the recovery.
3. Increasing permeability with depth in stratified dipping reservoirs was found to be a favourable condition for an up-dip gas injection into a volatile oil reservoir.

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