APPLICATION OF NEW COMPOSITIONAL SIMULATION APPROACH TO MODEL GRAVITY SEGREGATION IN VOLATILE OIL RESERVOIRS

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ABSTRACTS

In this paper, we investigate the recovery performance of gas injection from volatile oil reservoirs. Cross-sectional reservoir studies for investigating the gravity segregation during depletion and gas cycling in volatile oil reservoirs is discussed. Furthermore the effects of vertical permeability on gravity segregation in a homogeneous and horizontal reservoirs are investigated.

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 lean gas injection into a volatile oil reservoir. The new compositional simulation approach was validated through analytical and numerical methods, and it is unconditionally stable and as stable as fully compositional model.

The results show that an increase in vertical to horizontal permeability ratios results in an increase in the effect of gravity segregation and yield early gas breakthrough. On the other hand, the smaller the permeability ratios (vertical to horizontal), better are the recoveries due to resulting even layer sweeps. 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 word**s: compositional, equation of state, gravity segregation, volatile*

I. INTRODUCTION

A volatile oil is defined as a high shrinkage crude oil near its critical point (Moses, 1986). In a phase diagram, it is recognised as a type between a black-oil and a gas-condensate fluid. With deeper drilling, more reservoirs containing volatile crude oil and gas condensates have been found and the need for accurate and economic methods for studying the performance of such reservoirs has become important. In the early 1950’s several material balance methods were used for reservoir performance predictions (*e.g.*, Cook *et al*., 1951; Jacoby & Berry, 1957; Reudelhuber & Hinds, 1957). Cook *et al*. (1951) presented a method of estimating future reservoir performance and oil recovery of highly volatile type oil reservoirs. Later, Woods (1955) applied Cook *et al*. method to real field case study of that particular type of reservoirs. Reudelhuber & Hinds (1957) presented a compositional material balance method for the prediction of recovery from volatile oil depletion-drive reservoirs. Fluid compositions were determined from laboratory data and the actual reservoir study was conducted. Jacoby & Berry (1957) developed a tank-type model which used vapour-liquid equilibrium (VLE) and composition dependent densities and viscosities. This method used relative permeability data and multi-component flash calculations to predict oil and gas production as a function of reservoir pressure. Later, Cordell & Ebert (1965) showed that the greater accuracy of the volatile oil material balance was due to the consideration of the oil recovered from the gas phase.

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During the late of 1960's, the use of numerical compositional methods increased significantly with the rapid evolution of large scale, high speed, digital computers and the development of numerical mathematical methods. Numerical simulators, in general, utilise finite difference approximations to the rather complex partial differential equations that mathematically describe the physics and the thermodynamics of fluid flow in porous media. Simultaneously solving the continuity equations (after applying Darcy's Law), and the Equations of State for each phase, under the prescribed initial and boundary equations has become a standard method of developing a model for two-phase fluid flow in a porous media. Black oil simulators are used to simulate and predict reservoir performance by considering hydrocarbon fluids as two lumped components (phases) namely oil and gas. In this approach, inter-phase mass transfers were assumed to be a function of pressure only. For volatile oils, and gas condensates, this assumption may not be valid (Daltaban, 1986). Compositional models are used to simulate adequately the inter-phase mass transfer and predict reservoir performance when compositional effects cannot be neglected.

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.

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 minimise 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 mechanicms. In this paper the new compositional simulation approach is used to investigate the influence of gravity segregation and their magnitude in the case of lean gas injection into a volatile oil reservoir.

II. COMPOSITIONAL SIMULATION

A new compositional simulation approach for a volatile oil reservoir modeling was presented in previous publications (Syahrial & Daltaban, 1998; Syahrial & Daltaban, 1998; Syahrial 2010). 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 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. These equations are highly non-linear and they are linearised by using Newton-Raphson method. The resulting set of equations are solved by an efficient Conjugate Gradient based iterative technique to obtain pressures and saturations simultaneously, and hydrocarbon-phase saturations are deduced from their respective equations.

A. Generalised Flow Equations

The general flow equation used in the formulation can be found equations by summing up all the equations, applying mole constraint, and converting the resulting expressions into finite difference form namely:

- 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:

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

where transmissibility term T_l in the x-direction,

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

The same expression exists for y- and z-direction. In this formulation, all transmissibility term are treated implicitly. To obtain the hydrocarbon equation, both sides of oil and gas equations (Eqs. (2) and (3)) are multiplied by ξ_g^{n+1} and ξ_o^{n+1} respectively, and combined, hence:

- Hydrocarbon equation:

$$\xi_g^{n+1}\Delta\left[T_o^{n+1}\Delta\Phi_o^{n+1}\right]+\xi_o^{n+1}\Delta\left[T_g^{n+1}\Delta\Phi_g^{n+1}\right]+\xi_g^{n+1}\left(\xi_o q_o\right)^n+\xi_o^{n+1}\left(\xi_g q_g\right)^n$$
$$=\frac{V_r}{\Delta t}\left[\left(\phi\xi_o\xi_g S_h\right)^{n+1}-\xi_g^{n+1}\left(\phi\xi_o S_o\right)^n-\xi_o^{n+1}\left(\phi\xi_g S_g\right)^n\right] \quad (4)$$

where,

$$\left(S_h\right)^{n+1}=\left(S_o\right)^{n+1}+\left(S_g\right)^{n+1}$$

- Water equation:

$$\Delta\left[T_w^{n+1}\Delta\Phi_w^{n+1}\right]+\left(\xi_w q_w\right)^n=\frac{V_r}{\Delta t}\left[\left(\phi\xi_w S_w\right)^{n+1}-\left(\phi\xi_w S_w\right)^n\right] \quad (5)$$

B. Linearisation and Discretisation

It is clear that both water and hydrocarbon equations (Eqs. (4) and (5)) 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 the results are water and hydrocarbon equations in the oil-phase pressure and the water saturation forms. Effects of capillary pressure are treated explicitly.

The discretisation of water and hydrocarbon equations is carried out by applying a finite difference scheme using backward difference in time and central difference in space (Peaceman, 1967). This results in water and hydrocarbon equations having the form:

- Water Equation:

$$\begin{aligned}&W_{P_{i,j,k-1}}\,\delta P_{o_{i,j,k-1}}+W_{P_{i,j-1,k}}\,\delta P_{o_{i,j-1,k}}+W_{P_{i-1,j,k}}\,\delta P_{o_{i-1,j,k}}+\\&W_{P_{i,j,k}}\,\delta P_{o_{i,j,k}}+W_{P_{i+1,j,k}}\,\delta P_{o_{i+1,j,k}}+W_{P_{i,j+1,k}}\,\delta P_{o_{i,j+1,k}}+\\&W_{P_{i,j,k+1}}\,\delta P_{o_{i,j,k+1}}+W_{S_{i,j,k-1}}\,\delta S_{w_{i,j,k-1}}+W_{S_{i,j-1,k}}\,\delta S_{w_{i,j-1,k}}+\\&W_{S_{i-1,j,k}}\,\delta S_{w_{i-1,j,k}}+W_{S_{i,j,k}}\,\delta S_{w_{i,j,k}}+W_{S_{i+1,j,k}}\,\delta S_{w_{i+1,j,k}}+\\&W_{S_{i,j+1,k}}\,\delta S_{w_{i,j+1,k}}+W_{S_{i,j,k+1}}\,\delta S_{w_{i,j,k+1}}=C_{rw}\end{aligned}\quad (6)$$

- Hydrocarbon Equation:

$$\begin{aligned}&H_{P_{i,j,k-1}}\,\delta P_{o_{i,j,k-1}}+H_{P_{i,j-1,k}}\,\delta P_{o_{i,j-1,k}}+H_{P_{i-1,j,k}}\,\delta P_{o_{i-1,j,k}}+\\&H_{P_{i,j,k}}\,\delta P_{o_{i,j,k}}+H_{P_{i+1,j,k}}\,\delta P_{o_{i+1,j,k}}+H_{P_{i,j+1,k}}\,\delta P_{o_{i,j+1,k}}+\\&H_{P_{i,j,k+1}}\,\delta P_{o_{i,j,k+1}}+H_{S_{i,j,k-1}}\,\delta S_{w_{i,j,k-1}}+H_{S_{i,j-1,k}}\,\delta S_{w_{i,j-1,k}}+\\&H_{S_{i-1,j,k}}\,\delta S_{w_{i-1,j,k}}+H_{S_{i,j,k}}\,\delta S_{w_{i,j,k}}+H_{S_{i+1,j,k}}\,\delta S_{w_{i+1,j,k}}+\\&H_{S_{i,j+1,k}}\,\delta S_{w_{i,j+1,k}}+H_{S_{i,j,k+1}}\,\delta S_{w_{i,j,k+1}}=C_{rh}\end{aligned}\quad (7)$$

The system of equations above can be written in matrix form:

$$A\,\delta x^{k+1}=b^k \quad (8)$$

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.

C. Composition and Saturation Equations

Compositions are computed explicitly by a method developed by Tsutsumi and Dixon (1972). The overall compositions of the components can be expressed as:

$$z_m^{n+1}=\left[\frac{\Delta\left[x_m^{n+1}T_o^{n+1}\Delta\Phi_o^{n+1}+y_m^{n+1}T_g^{n+1}\Delta\Phi_g^{n+1}\right]+\left(x_m\xi_o q_o+y_m\xi_g q_g\right)^n+\dfrac{V_r}{\Delta t}\left[z^n\left\{\left(\phi\xi_o S_o\right)+\left(\phi\xi_g S_g\right)\right\}^n\right]}{\Delta\left[T_o^{n+1}\Delta\Phi_o^{n+1}+T_g^{n+1}\Delta\Phi_g^{n+1}\right]+\left(\xi_o q_o+\xi_g q_g\right)^n+\dfrac{V_r}{\Delta t}\left[\left\{\left(\phi\xi_o S_o\right)+\left(\phi\xi_g S_g\right)\right\}^n\right]}\right] \quad (9)$$

Oil and gas saturations are calculated as the final result of a series of computations form:

$$S_o^{n+1}=\left[\frac{\Delta\left[T_o^{n+1}\Delta\Phi_o^{n+1}\right]+\left(\xi_o q_o\right)^n+\dfrac{V_r}{\Delta t}\left[\left(\phi\xi_o S_o\right)^n\right]}{\dfrac{V_r}{\Delta t}\left[\left(\phi\xi_o\right)^{n+1}\right]}\right], \quad (10)$$

$$S_g^{n+1}=\left[\frac{\Delta\left[T_g^{n+1}\Delta\Phi_g^{n+1}\right]+\left(\xi_g q_g\right)^n+\dfrac{V_r}{\Delta t}\left[\left(\phi\xi_g S_g\right)^n\right]}{\dfrac{V_r}{\Delta t}\left[\left(\phi\xi_g\right)^{n+1}\right]}\right]. \quad (11)$$

D. Validation Procedures

The equations presented in the previous section were coded into a computer program that provides a field-scale

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reservoir simulator which models the behaviour of compositional processes and in particular the behaviour of volatile oil reservoirs. The results from the simulation procedure are validated by comparing them against both analytical and numerical models. The Buckley-Leverett method (Buckley & Leverett, 1942) was used as the analytical model. Numerical validation was provided by *Eclipse300* (a fully compositional simulator that is the *de rigour* industry standard (GeoQuest, 1996)). The validation tests have shown that this formulation gives sufficiently close approximations to the analytical Buckley-Leverett solution and other numerical methods (Syahrial, 2010). The new model requires less number of equations to be solved per time step than the fully implicit method and only needs one to two iterations per time step, this formulation is as cheap as IMPES and is as accurate as fully implicit methods.

III. APPLICATIONS

After validating against analytical and numerical methods, the simulator was used to model recovery from volatile oil reservoirs. The objective of this section is to carry out a theoretical investigation into the recovery performance Gas Injection from volatile oil reservoirs. Cross-sectional studies for investigating the gravity segregation during depletion and gas cycling in volatile oil reservoirs is discussed. Furthermore the effects of vertical permeability on gravity segregation in a homogeneoues and horizontal reservoirs are investigated.

A. Cross-Sectional Studies

In this section, two-dimensional studies in which flow is permitted in only the horizontal and vertical directions are discussed. These studies are intended to illustrate the effect of gravity segregation on the oil recovery in the case of gas injection into volatile oil reservoirs. The recovery efficiencies of immiscible and miscible gas displacement due to gravity segregation are affected by:

1. Increased permeability (either horizontal or vertical).
2. Increased density difference.
3. Increased mobility ratio.
4. Decreasing production rates.

A compositional simulation approach is fully implemented to investigate the influence of gravity segregation and their magnitude in the case of lean gas injection into a volatile oil reservoir. 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.

Table 1
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, θ	0	0
Horizontal Permeability, k_h	200 mD	1.97×10^{-13} m^2
Porosity, ϕ	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	4×10^{-6} psi^{-1}	5.80×10^{-7} kPa^{-1}
Water Compressibility, c_w	3×10^{-6} psi^{-1}	4.35×10^{-7} kPa^{-1}

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Table 2
Fluid compositions and properties at reservoir conditions

Component	Mole Frac.	T_c (°F)	p_c (psia)	Z_c	MW	●	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

B. Gravity Segregation in Homogeneous and Horizontal Reservoirs

The reservoir domain selected for the purposes is a two-dimensional cross-section reservoirs. The length of the reservoir is 3000 ft, width is 50 ft and the thickness of the pay zone is 100 ft. The average horizontal permeability and porosity are 200 mD and 15% respectively. 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 1 shows the other relevant data of this study.

Table 3
Compositions of the lean injection gas

Lean Gas	C_1	C_2	C_3	C_4	C_5	C_6	C_7^+
Mole Frac.	0.85	0.01	0.01	0.03	0.01	0.01	0.08

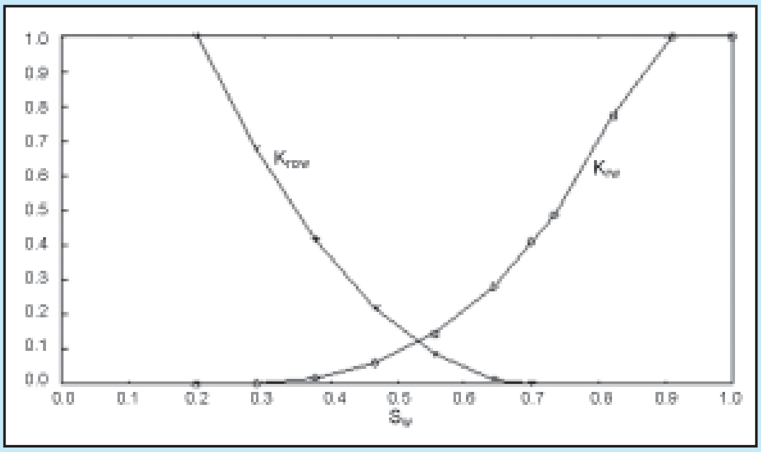

Figure 1
Water-oil relative permeability curves

The fluid used in this study is that of OIL-6 (Coats & Smart, 1982) and Table 2 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. The relative permeability curves are shown in Figures 1 & 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. Lean gas injection with a composition listed in Table 3 is used as the gas cycling processes, and assumed

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that miscibility occurred during the injection. To compare the relative performance of gas cycling with different values of vertical to horizontal permeability ratio, natural depletion is also conducted in this study.

C. Effect of Vertical Permeability on Gravity Segregation

In this section the effect of vertical permeability on gravity segregation in homogeneous and horizontal reservoirs is investigated. Three different ratios of vertical to horizontal permeability k_v/k_h: 1.0, 0.1 and 0.01 respectively are used in the modelling procedure. Also, the depletion processes is modelled with a ratio of vertical to horizontal permeability of 0.1.

Figures 3 through 5 show the methane saturation distribution for each case studied after 18.8% HCPV (300 days) of lean gas injection. It is clear from these Figures that an increase in vertical to horizontal permeability ratios results in an increase in the effect of gravity segregation and yield early gas breakthrough. Table 4 shows the relative breakthrough times (defined as approximately 2% Methane increase in the producing stream) and the corresponding C_7^+ (a component that characterises the liquid) recoveries. It is also clear from this Table that smaller the permeability ratios (vertical to horizontal) better are the recoveries due to resulting even layer sweeps.

Table 5 shows the comparison of C_7^+ recoveries and gas-oil ratios after 600 days (37% HCPV) of gas injection. Figures 6 & 7 show the temporal variations of C_7^+ production rate and gas-oil ratio respectively for the same period. The C_7^+ recovery for k_v/k_h: 0.01 is about 1.6 times that can be obtained from k_v/k_h: 1.0. The gas-oil ra-

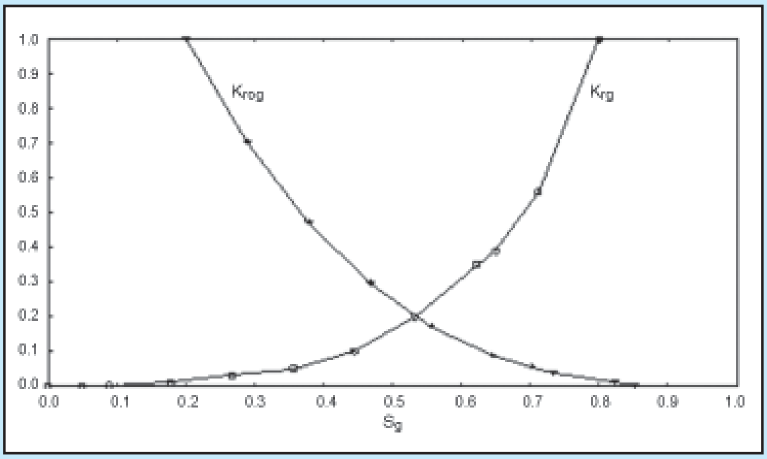

Figure 2
Gas-oil relative permeability curves

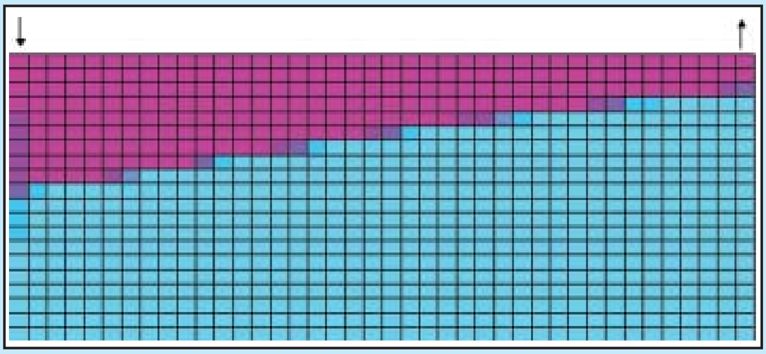

Figure 3
Gas saturation in a horizontal reservoir, k_v/k_h = 1.0

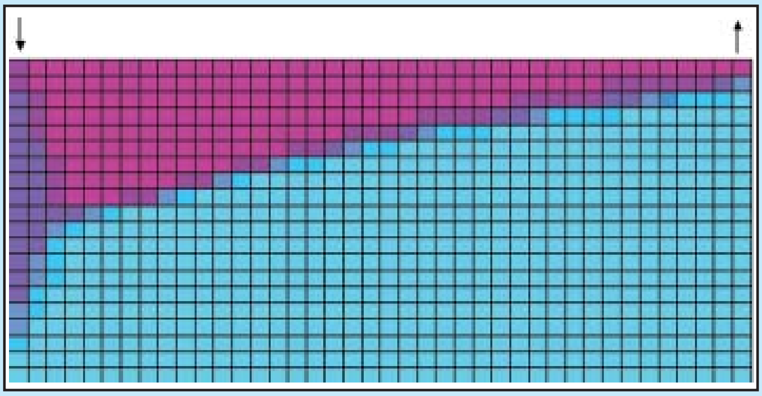

Figure 4
Gas saturation in a horizontal reservoir, k_v/k_h = 0.01

Table 4
C_7^+ recovery at breakthrough

k_v/k_h	Breakthrough Time (Days)	C_7^+ Recovery (frac.)
1.00	130	0.31
0.10	250	0.32
0.01	340	0.33

Table 5
C_7^+ recovery and GOR after 600 days

k_v/k_h	C_7^+ Recovery (frac.)	GOR MSCF/STB)
1.00	0.16	5.50
0.10	0.18	5.40
0.01	0.25	4.43

tio for Figure 7 shows dramatic increase after the breakthrough for each injection case as expected. At 600 days, their values as given in Table 5 demonstrate that the smallest permeability case exhibit marked difference than others. For the cases of k_v/k_h: 1.0 and k_v/k_h: 0.1, the results are similar due to not only the less contrast in the permeabilities but also to the balance between viscous to gravity forces. For a k_v/k_h of 0.01, the viscous forces have more control on the results.

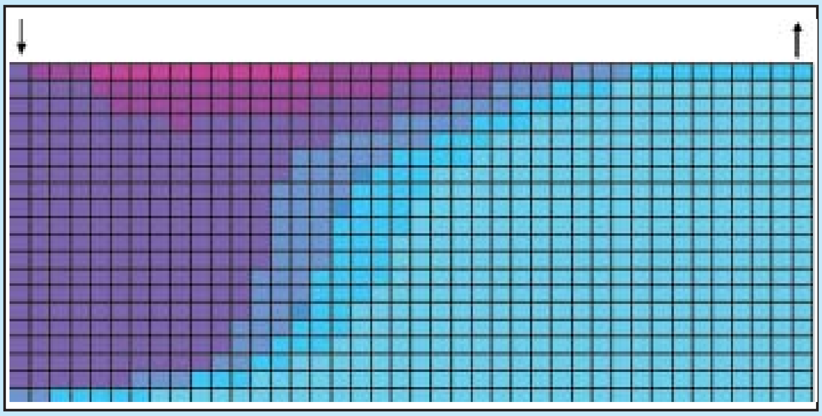

Figure 5
Gas saturation in a horizontal reservoir, k_v/k_h= 0.01

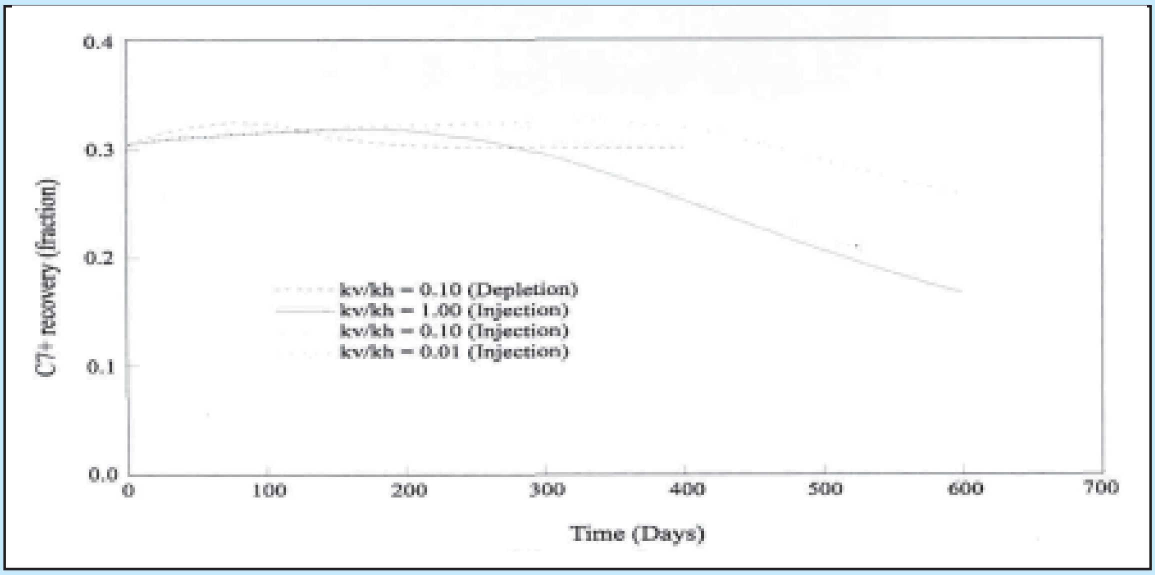

Figure 6
Temporal variation of C_7^+ in a horizontal reservoir

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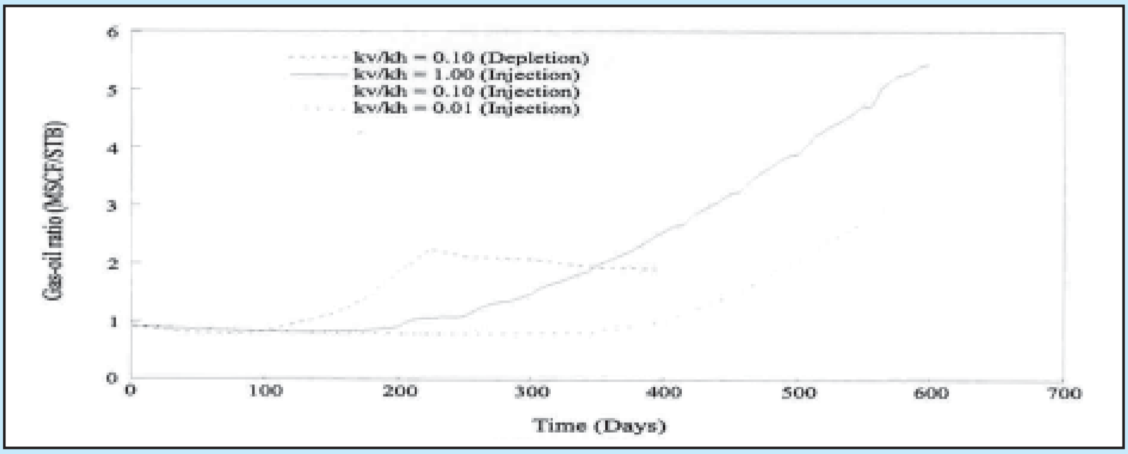

Figure 7
Gas-Oil ratio versus time in a horizontal reservoir

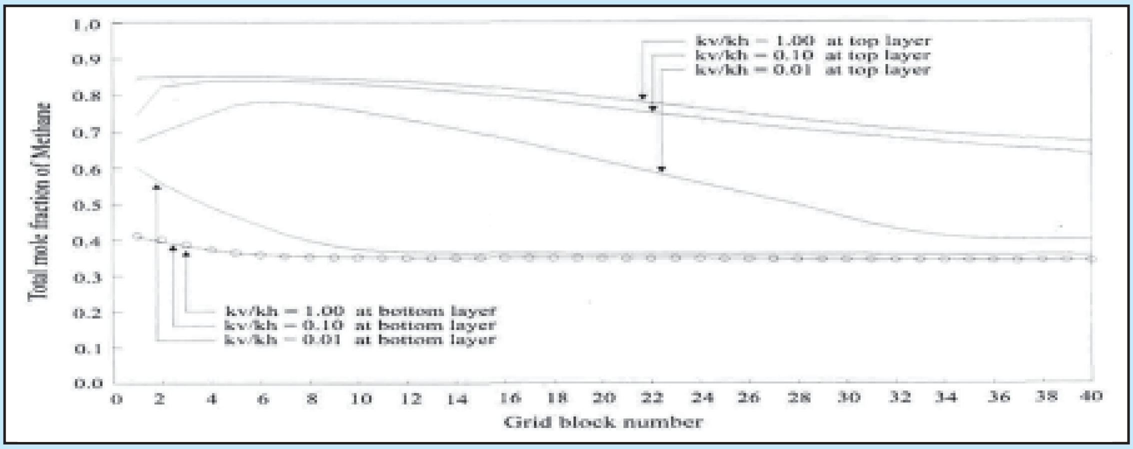

Figure 8
Total mole fraction of methane after 300 days

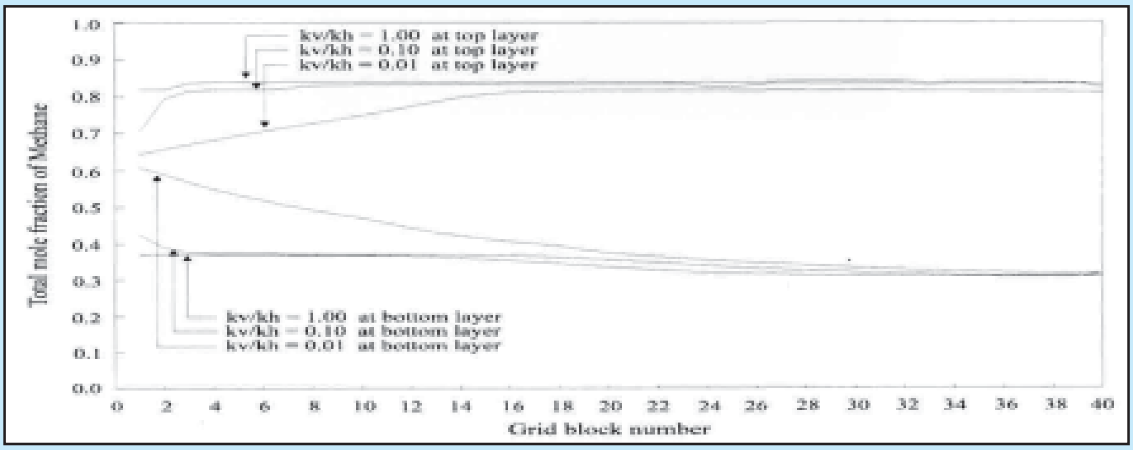

Figure 9
Total mole fraction of methane after 1000 Days

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Figures 8 & 9 show the distribution of Methane mole fraction after 300 and 1000 days respectively at the top and bottom of the reservoir for each case studied. The Figure 8 shows that the total mole fraction of Methane increases rapidly in the top layer for k_v/k_h of 1.0 and 0.1 in all grid blocks. As injection proceeds, the total mole fraction of Methane with k_v/k_h: 0.01 reached the same level as the model with k_v/k_h is 1.0 and 0.1. Figure 9 confirms that situation.

In the case studies presented in this section, it was demonstrated that the gravity forces have considerable effect on volatile oil recovery via gas injection and the need for determining not only the fluid characteristics but also the reservoir heterogeneities.

IV. CONCLUSIONS

1. The model formulation developed has an implicit transmissibility term, an implicit for oil-phase pressure and water saturation and explicit equation for the overall composition of each hydrocarbon component that satisfies thermodynamic equilibrium. It is unconditionally stable like the Fully Implicit approach and can be as cheap as IMPES.
2. The new model requires less number of equations to be solved per time step than the fully implicit method and only needs one to two iterations per time step, this formulation is as cheap as IMPES and is as accurate as fully implicit methods.
3. An increase in vertical to horizontal permeability ratios results in an increase in the effect of gravity segregation and yield early gas breakthrough. The smaller the permeability ratios (vertical to horizontal), better are the recoveries due to resulting even layer sweeps.
4. 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.

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