The Impact of Heterogeneity on Tertiary Miscible Gas Injection

By

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A report submitted in partial fulfilment of the requirements for the MSc and the DIC

September 2013
DEDICATION OF OWN WORK

I declare that this thesis *The Impact of Heterogeneity on Tertiary Miscible Gas Injection* is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature:

Name of Student: Dastan Sartekenov

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I am very grateful to my supervisor, Professor Ann Muggeridge, whose direction, guidance and recommendations were extremely helpful for the project.

I would like to also thank Bilal Rashid for his advice and support, especially for his help related to the software usage.

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The Impact of Heterogeneity on Tertiary Miscible Gas Injection

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Abstract

Use of Enhanced Oil Recovery (EOR) techniques is becoming increasingly important due to fewer new large field discoveries. One of the widespread EOR processes to further increase oil production is the tertiary injection of miscible gas after waterflooding. However, the efficiency of this process is largely dependent on reservoir properties, specifically permeability heterogeneity, which bears a high degree of uncertainty. In the most unfavorable cases injected miscible gas migrates to the top of the reservoir (due to gravity) or channel through the most permeable layers, thus reducing macroscopic sweep and consequently the recovery factor, since it is both less dense and less viscous than oil and water. This raises the issue of assessing the impact of permeability heterogeneity and viscous-to-gravity ratio on tertiary miscible gas injection in order to efficiently plan the EOR process.

This study is an attempt to quantify the impact of permeability heterogeneity on tertiary miscible gas injection using dimensionless numbers, namely gas breakthrough in pore volumes injected as a function of vorticity-based heterogeneity index ($H_v$) proposed by Rashid et al. (2012) and gravity-viscous number ($G$) by Fayers and Muggeridge (1990). This is carried out on simple homogeneous cases and layers from the more realistic Brent-type SPE 10 Model 2 (Christie and Blunt 2001). The resulting plots are used to identify visible relationships between heterogeneity and gravity effects, in terms of flow regimes and their boundaries. The result of the work is the 3D phase diagram of the breakthrough time as a function of ($H_v$) and ($G$). The learning point of this study is that the effects of gravity and heterogeneity on the performance of the tertiary miscible gas injection for heterogeneous reservoirs are complex and may not be as straightforward as for the systems with uniform permeability distributions or secondary miscible gas injection.

Introduction

The depletion of oil reserves around the globe and the resulting high oil prices are making EOR techniques more popular as a way of maximizing oil production from existing mature fields after waterflooding, where the average recovery factor is in the range of 30-40%. Considerable quantities of oil are left behind after waterflooding due to the low local displacement efficiency of this technique. Tertiary miscible gas injection method is aimed at increasing the local displacement efficiency which can be achieved by injecting gas which is miscible with the residual oil, but the macroscopic sweep efficiency of gas injection is lower than that of waterflooding (Chen et al. 1994). The efficiency of such a process is dependent on the reservoir heterogeneity and interaction of it with factors such as injection rate, mobility ratio, density difference between the oil and the displacing fluid and capillary pressure curves (Zhou et al. 1997).

Although the feedback from the industry confirms the viability of applying tertiary miscible gas injection as a means of maximizing the oil production, they all stress on the importance of capturing the heterogeneity of the reservoir. Reservoir heterogeneity or (to be more specific in terms of reservoir engineering) permeability heterogeneity is highly uncertain in most reservoirs, but can have a large impact on the sweep efficiency in the reservoir. The effects of permeability heterogeneity are complex, depending upon flow direction, well pattern, geological depositional environment and the production drive mechanism (Giordano et al. 1985; Tidwell and Wilson 2000). It may happen that the reservoir heterogeneity is favorable for applications of such EOR techniques as in the giant Prudhoe Bay field, where discontinuous shale bodies prevent the gravity segregation between the injected gas and the displaced oil. It is predicted that the residual oil saturation will be brought to less than 10% by abandonment (from 25% after secondary water injection (Brodie et al. 2012)). Burns et al. (2002) highlighted the importance of knowing the reservoir geology and the need for fine scale modeling to capture the heterogeneity when discussing the early gas breakthrough experienced in the Alwyn North field. A very detailed heterogeneity is important when predicting EOR model and its effect is most pronounced close to the injectors, producers and in the middle of the patterns. Failure to capture the critical heterogeneity may result in over prediction of the recovery (Moreno et al. 2013).

Reservoir heterogeneity has been widely acknowledged as an important factor in determining reservoir performance during EOR processes (Li and Lake, 1995). The effect of heterogeneity has been studied leading to the fact that different
reservoir heterogeneity types affect reservoir performance in different ways (Weber 1982; Kjonsvik et al. 1994; Choi et al. 2011). When the flow is viscous-dominated, the displacing fluid may channel through more permeable layers (due to heterogeneity) and result in early breakthrough; adverse viscosity ratio exacerbates this effect by forming viscous fingers, which flow through displaced oil and lead to even earlier breakthrough (Wright et al. 1983; Greenkorn et al. 1988; Houseworth 1991). Gravity may also impact the displacement of oil by forming a gravity tongue on the top of the reservoir and resulting in earlier breakthrough time of the displacing fluid. That depends on the type of heterogeneity present, as well as the density difference between the oil and displacing fluid. If the flow is capillary-dominated, dispersion of the front may also result in early breakthrough (Dietz 1953; Fayers and Mugggeridge 1990), although this is only important in immiscible displacements.

Reservoir heterogeneity, in most of the cases, will lead to earlier breakthrough of the displacing fluid and poor displacement efficiency, leaving high amounts of oil behind. Recovery efficiency is usually in the range of 5 - 80% (Tyler et al. 1994). Such a wide range can be explained with high uncertainty associated with the distribution of reservoir (permeability) heterogeneity distribution. Despite huge improvements in the field of reservoir characterization in the recent decade, the details of spatial permeability distribution in any given reservoir are generally not known (de Marsily et al. 2005). To be able to assess the impact of the heterogeneity uncertainty in the process of studying possible EOR schemes for a particular field, ideally, displacement multiphase flow simulations through numerous realizations of detailed geological models are performed. This, however, is often not possible due to constraints set by computing power and time limitations.

The impacts of the heterogeneity and flow regime are best described and quantified using dimensionless numbers. Zhou et al. (1997) attempted to combine the various dimensionless numbers to characterize flow coming up with a 3D phase diagram showing various flow regimes (Figure 1), but this study did not take into account the heterogeneity of the media in which the flow takes place.

![Figure 1: 3D phase diagram of various flow regimes described by dimensionless numbers (Zhou et al. 1997)](image)

A variety of studies have tried to quantify the impact of reservoir permeability heterogeneity with the use of dimensionless numbers. Static measures of the heterogeneity, such as the coefficient of variation of permeability (Moisiss and Wheeler 1990), are based on the statistics of the permeability field in the absence of flow. It was derived from the Dykstra-Parsons coefficient (Dykstra and Parsons 1950) \( V_{dp} \), which was initially correlated against waterflood performance indicators, assuming a layered reservoir with no cross-flow between layers and piston–like movement of the water front in the layers. Another static measure is the Lorenz coefficient (Shmalz and Rahme 1950), which is based on applying the flow capacity of a layer within the reservoir and its thickness to assess the recovery. These indices show good correlation with the recovery factors for the systems investigated, but did not consider more complex spatial distribution. In contrast to static indices, dynamic indices are derived from numerical simulations and thus incorporate the interaction of flow with heterogeneity, taking into account well patterns, PVT properties and production mechanisms. The first effort was that of Koval (1963), who attempted to capture the effect of viscous fingering in miscible floods. This, however, requires detailed multiphase displacement simulation, which is computationally complex and thus is not suitable for a quick characterization of different reservoir models. Shook and Mitchell (2009) extended the original static Lorenz coefficient (now called the dynamic Lorenz coefficient) by including the flow information with the help of applying the time of flight of streamlines and their volumetric flow rates. Calculation of this index is computationally easier, because it only requires a single-phase pressure-solve to be determined. The recent work of Rashid et al (2012) introduced a new vorticity-based heterogeneity index, which showed improved correlation with realistic geological models compared to Dykstra-Parson’s index and dynamic Lorenz coefficient.

The aim of this study is to investigate and assess the impact of permeability heterogeneity and gravity on tertiary miscible gas injection. The results will be analyzed with the help of vorticity-based heterogeneity index proposed by Rashid et al. (2012) and the gravity-viscous number by Fayers and Mugggeridge (1990). Simulations will be carried out using simple homogeneous, two-layered cases and more realistic Brent-type SPE 10 Model 2 (Christie and Blunt 2001) heterogeneous layers. Plots will be constructed to identify relationships, flow regimes and their boundaries. The work will rely on previously derived results of similar studies carried out by Rashid et al (2012, presented in ECMOR XIII) on secondary gas injection and Fagbowore (2012) on the use of representative permeability value in determining the gravity-viscous dimensionless number.
Methodology

Input specifications

Numerical simulations were performed with the help of the Fortran-based software (MISTRESS), which is capable of simulating the behaviour of unstable flows in both miscible and immiscible floods. It exploits an implicit pressure and explicit saturation (IMPES), finite difference formulation with flux-corrected transport for solving the transport equation and removing the undesired generated oscillations that result from using two-point upstream weighting. The algorithm for the software was first presented by Christie and Bond (1987) and was validated by comparing its results with the findings of various experiments performed by Blackwell et al. (1959), Christie (1989), Christie et al. (1990), Muggeridge et al. (2002) and Muggeridge et al. (2005). The software is based on using dimensionless variables, which makes it particularly easy to compare the results of different reservoir models. In order to minimize the time it takes to run the simulations, the following assumptions were incorporated in the process of developing it:

- The phases present are incompressible fluids;
- Two phases and three components are present (oil, water and solvent);
- Oil and solvent are FCM (first contact miscible);
- Oil/solvent mixture viscosity is defined by quarter-power mixing rule.

In this study, each reservoir model is set to be initially saturated with oil and conate water saturation of $S_w=0.15$. Uniform constant rate injection conditions at the injector well and a constant bottom hole pressure at the producer well were imposed. The first step was to perform water injection of 0.8 pore volume (further PV) with the following input parameters:

- Relative permeabilities of water and oil are determined using Corey equations:

$$k_{rw} = k_{rw(max)} \times \left( \frac{S_w - S_{wcr}}{1 - S_w - S_{wr}} \right)^N_w \quad k_{ro} = k_{ro(max)} \times \left( \frac{1 - S_w - S_{or}}{1 - S_w - S_{or}} \right)^N_o \quad (1)$$

where $k_{rw(max)} = k_{ro(max)} = 1$ (maximum relative permeabilities of oil and water) and are $N_o = N_w = 2$ (Corey parameters for oil and water) and $S_{or} = 0.2$ (residual oil saturation);

- Densities of oil and water assumed to be equal ($\rho_o = \rho_w = 1$, water density regarded as the reference density);

- Viscosities of the fluids were taken as $\mu_w = 2$ and $\mu_o = 1$ (water viscosity $\mu_w = 1$).

The next step was to simulate gas injection using the new saturations of oil and water obtained as a result of water injection simulation.

A grid size of 100×100 was chosen both for homogeneous and two-layered cases with a cell aspect ratio of 0.545. This was based on previous grid sensitivity studies performed by Rashid et al. (2012). Tertiary gas breakthrough time in PV injected (PVI) for all cases and incremental oil production in PV for were obtained and used in conjunction with dimensionless gravity-viscous number and vorticity-based heterogeneity index to identify flow regimes. Breakthrough time was defined as the PV injected before a fractional flow of 1% of the injected fluid is achieved at the production well. Incremental oil production is the oil produced by tertiary gas injection only, i.e. oil production achieved by secondary water injection is not included.

Dimensionless numbers used

The gravity-viscous dimensionless number used in this work is the reciprocal of the viscous-to-gravity number suggested by Fayers and Muggeridge (1990), defined as:

$$G = \frac{1}{2} \frac{\Delta \rho g k}{v (1 - \frac{1}{3}) \mu_o H} \quad (2)$$

where $\Delta \rho$ is the difference between the densities of displaced fluid (oil) and displacing fluid (solvent), $v$ is the total injection velocity (equal to 1 in our case), $M$ is the mobility ratio ($\mu_o / \mu_g$), $L$ is the reservoir length, $H$ is the reservoir thickness and $k$ is the permeability of the reservoir, which has been taken as the geometric mean of effective horizontal and vertical permeabilities of the reservoir. The advantage of using this permeability formulation was shown in the work of Fagbowore (2012), who gave better characterization of the viscous to gravity ratio in anisotropic reservoirs than using either the effective vertical permeability as suggested by Fayers and Muggeridge (1990) or the arithmetic average as suggested by Dietz (1953). The geometric mean term of permeability was derived by applying the effective aspect ratio suggested by Shook et al. (1992):

$$R_L = L H \sqrt{\frac{k_v}{k_h}} \quad (3)$$

and combining Equations (1) and (2) and assuming $k = k_h$ yields:

$$G = \frac{1}{2} \frac{\Delta \rho g k_h}{v (1 - \frac{1}{3}) \mu_o H} \frac{L}{\sqrt{k_h}} \quad (4)$$

which after simplifying yields the effective permeability as the geometric mean of horizontal and vertical permeabilities:
$$G = \frac{12 \Delta \rho g k v}{2 \mu (1-\frac{v}{M}) \mu_0 H} \quad \text{……………… (5)}$$

Physically, the gravity-viscous number characterizes whether the flow in the reservoir is viscous- or gravity-dominated on the Darcy scale. In a given homogeneous reservoir, gravity effects dominate when \( G > 1 \) and the larger the number, the more profound the effect of gravity during displacement, which results in forming of a gravity tongue. By looking at the definition of the gravity-viscous number, it is obvious that this effect can be exacerbated by increasing the density difference between the displaced and displacing fluid. For smaller values of \( G \) (<0.1), the displacement is affected by viscous effects and the smaller this number the more viscous-dominated the flow is, which may result forming of viscous fingers. Analogously, this effect can be exacerbated by increasing the mobility ratio of the displaced and displacing fluid.

In order to be able to quantify the impact of the permeability heterogeneity of the reservoir, the vorticity-based heterogeneity index suggested Rashid et al. (2012) was used in this work. The development of this index is related to the work of Heller (1966) who showed that the vorticity of the displacement (\( \mathbf{V}_d \)) characterizes the rate of change along the interface between two miscible fluids. Rashid et al. (2012) modified that relationship in order to express it in dimensionless terms:

$$L \frac{\nabla \mathbf{V}_d}{|\mathbf{v}|} = \frac{1}{\varphi} \frac{L n M}{|\mathbf{v}|} + \frac{k \rho g}{\mu |\mathbf{v}|} - \frac{1}{|\mathbf{v}|} \left( \frac{\nabla D \nabla c}{|\mathbf{v}|} \right) \times L \nabla c + L \left[ \frac{\ln k}{\varphi} \right] \times \frac{\mathbf{v}}{|\mathbf{v}|} \quad \text{…………….. (6)}$$

where \( \mathbf{v} \) is the vector of Darcy velocity, \( D \) is the dispersion tensor, \( c \) is the concentration and \( \varphi \) is the porosity term. The three terms on the right hand side of the equation represent the mobility, gravity and diffusion terms respectively. The fourth term was used to motivate the development of the vorticity-based heterogeneity index \( (H_v) \) defined as:

$$H_v = \frac{1}{C_v(|\omega|)} \quad \text{…………….. (7)}$$

where \( C_v(|\omega|) \) is the coefficient of variation of the voracity (\( \omega \)) field. From the Equation 6 one can conclude that there are 4 contributors to the flow regime: mobility ratio, gravity (or density difference), diffusion and heterogeneity and the term with the highest magnitude is to dominate the flow. Neglecting the impact of diffusion on flow in reservoir-scale flow (which is influential in the pore-scale) and assuming constant mobility ratio, gravity and heterogeneity play the main role in determining the flow regime. This equation also suggests that when gravity effects are dominant, the heterogeneity does not play a major role. However, as the flow becomes more viscous-dominated, the impact of heterogeneity prevails.

Rashid et al. (2012) in their study showed the advantage of using vorticity-based heterogeneity index over Dykstra-Parsons coefficient and dynamic Lorenz coefficient by obtaining a much better correlation against secondary gas injection breakthrough time. The study was performed using layers form the realistically heterogeneous SPE 10 Model 2 (Christie and Blunt 2001). The comparisons with Dykstra-Parsons coefficient and dynamic Lorenz coefficient are given in Figure 2. It should be noted that the higher is \( H_v \) (close to 1), the more homogeneous the reservoir is. Correspondingly, lower \( H_v \) values (close to 0) characterize more heterogeneous reservoirs.

![Figure 2: Breakthrough time as a function of three different measures of heterogeneity (Rashid et al. 2012).](image-url)
The Impact of Heterogeneity on Tertiary Miscible Gas Injection

Homogeneous system with permeability anisotropy
Since real reservoirs are usually characterized by the anisotropy and the heterogeneity of the permeability distribution, it is essential to understand how each of these factors affects the performance of tertiary miscible gas injection. The first case that was investigated is the homogeneous reservoir with varied anisotropy. Water injection was first simulated and was compared with Buckley-Leverett analysis to validate the simulation results. That was followed by gas injection with constant horizontal permeability ($k_h$) with varied vertical permeability ($k_v$) for different $G$ numbers in order to see the relationship between anisotropy and gravity effects. The model properties and the parameters used are presented in Table 1. The time to breakthrough of solvent in PV were obtained for performed simulations.

<table>
<thead>
<tr>
<th>Table 1: Model properties and parameter variations used for the homogeneous system.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Model properties</strong></td>
</tr>
<tr>
<td>Grid size</td>
</tr>
<tr>
<td>Grid cell aspect ratio ($H/L$)</td>
</tr>
<tr>
<td>Oil and solvent density contrast ($\rho_o - \rho_s$)</td>
</tr>
<tr>
<td>Oil viscosity to solvent viscosity ($\mu_o / \mu_s$)</td>
</tr>
<tr>
<td>First contact miscible displacement</td>
</tr>
<tr>
<td><strong>Parameter variations</strong></td>
</tr>
<tr>
<td>Horizontal permeability ($k_h$)</td>
</tr>
<tr>
<td>Vertical permeability ($k_v$)</td>
</tr>
<tr>
<td>Gravity-viscous number ($G$)</td>
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</table>

Two-layered system with different permeability ratios
The second case investigates into the impact of permeability heterogeneity on tertiary miscible gas injection. Heterogeneity here is expressed by the layered nature of the reservoir. Numerical simulations for a two-layered system when the flow is parallel to layering were carried out as well in a similar fashion as with the homogeneous system (without permeability anisotropy, but with different layer permeabilities). Two cases were considered: firstly, when the more permeable layer is on top and in the second case when it is in the bottom (as shown in Figure 3).

![Figure 3: Two-layered system with different locations of the more permeable layer.](image)

The model properties and the variation parameters for this case are presented in Table 2 below. It should be noted that the grid size (100×100) used and the aspect ratio (0.545) were chosen based on grid sensitivity studies performed by Rashid et al. (2012).

<table>
<thead>
<tr>
<th>Table 2: Model properties and parameter variations used for the two-layered system.</th>
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<tbody>
<tr>
<td><strong>Model properties</strong></td>
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<td>Grid size</td>
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<tr>
<td>First contact miscible displacement</td>
</tr>
<tr>
<td><strong>Parameter variations</strong></td>
</tr>
<tr>
<td>Permeability ratio ($k_1:k_2$)</td>
</tr>
<tr>
<td>Gravity-viscous number ($G$)</td>
</tr>
</tbody>
</table>

The effective vertical permeability of the system was determined as the harmonic mean of vertical permeabilities of the layers and the effective horizontal permeability as the arithmetic mean of horizontal permeabilities of the layers. The effective permeability of the system was determined as the geometric mean of the effective horizontal and vertical permeabilities of the system.
Realistic SPE 10 Model 2 heterogeneous reservoir models

In order to assess the impact of heterogeneity and gravity for more realistic cases, SPE10 Model 2 (Christie and Blunt 2001) layers were used as reservoirs, each layer being represented with a specific permeability field (Figure 4). It is a finely gridded 3D Brent type reservoir model consisting of 85 layers, each of them represented on a 60×220 grid, where the top 35 layers form the prograding near-shore environment from the Tarbert formation and the bottom 50 form the fluvial Upper-Ness formation.

![Figure 4: 3D representation of SPE10 Model2 Brent type reservoir in terms of permeability distribution.](image)

Each layer was extracted and located vertically on a horizontal 2D grid of 220×60 with a cell aspect ratio of 0.545 (see Figure 5 as an example). This was done in order to capture as wide a variation of heterogeneity as possible when altering the gravity-viscous number ($G$).

![Figure 5: Setup of layer 59 with its own permeability field.](image)

Model properties and parameter variations used in numerical simulations for SPE10 Model 2 layers are presented in Table 3 (see below).

<table>
<thead>
<tr>
<th>Table 3: Model properties and parameter variations used for the heterogeneous SPE10 Model2 reservoir layers.</th>
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<tbody>
<tr>
<td><strong>Model properties</strong></td>
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<tr>
<td>Grid size</td>
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<tr>
<td>First contact miscible displacement</td>
</tr>
<tr>
<td><strong>Parameter variations</strong></td>
</tr>
<tr>
<td>Heterogeneity index ($H_v$)</td>
</tr>
<tr>
<td>Gravity-viscous number ($G$)</td>
</tr>
</tbody>
</table>

The heterogeneity indices ($H_v$) for each of the layers (for determining the $G$ number) were calculated previously by Rashid et al. (2012).
Results and Discussion

Effect of permeability anisotropy and gravity in a homogeneous system

The results of the tertiary gas injection simulations performed for a range of gravity-viscous numbers (G) in the homogeneous reservoir with anisotropy are presented in the plots in Figure 6. The trends are as expected, since they indicate that breakthrough time and as a result, the recovery, decrease when the gravity effects become dominant (G>1) due to the formation of the gravity tongue in the upper part of the reservoir. Permeability anisotropy defines the performance of the reservoir for cases when G<0.1 and is characterized by delayed breakthrough time and higher recovery. When G is in the range of 0.1 to 1, the viscous effects are suppressed by gravity and give way to the formation of the gravity tongue as G is increased further. Figure 7 shows the impact of increasing gravity effects on the concentration distribution during the displacement in a homogeneous isotropic system (k_v/k_h=1) as an example.

Figure 6: Plots of tertiary gas breakthrough time and incremental oil recovery at tertiary gas breakthrough as a function of gravity-viscous number for the homogeneous reservoir with permeability anisotropy.

Figure 7: Concentration map at tertiary gas breakthrough for the homogeneous isotropic system (k_v/k_h=1). Red is the injected gas and blue is oil and water.

Another way of looking at the results is presented in Figure 8, which shows the impact of permeability anisotropy on breakthrough time and recovery at different gravity-viscous numbers.

Figure 8: Plots of tertiary gas breakthrough time and incremental oil recovery at tertiary gas breakthrough as a function of permeability anisotropy at different G numbers for the homogeneous system.
Some features can be seen in these plots; for cases where the displacement is more viscous-dominated \((G=0.01, 0.1)\), increasing vertical permeability (up to \(k_v/k_h=1\)) results in earlier breakthrough and lower recovery. This effect is illustrated in Figure 9 and it can be seen that fewer and larger viscous fingers can be seen as the vertical permeability \((k_v)\) is increased, which results in a poorer displacement. This is because viscous cross flow allows larger fingers to ‘steal’ solvent from the smaller, less strongly growing fingers when the vertical permeability is higher.

Another observation is when the flow is more dominated by gravity \((G=1, 10)\) the gas breakthrough time is delayed and recovery is enhanced as the vertical permeability \((k_v)\) is increased to be higher than the horizontal permeability. This is also illustrated in Figure 10 and it can be noticed that at very high vertical permeabilities, the resulting gravity tongue provides better sweep efficiency. It should be noted, however, that it is very unusual from geological point of view when \(k_v < k_h\), it is most common when \(k_v < k_h\) due to the layered nature of sedimentary rocks.

Two-layered system: permeability contrast and order of layering

The results of the analysis of the impact of gravity in tertiary gas injection for the two-layered system with the case when the more permeable layer is on top (Figure 3) are shown in Figure 11. As expected, the breakthrough time is earlier and recovery decreases as the flow becomes more gravity-dominated \((G>1)\) due to formation of the gravity tongue. The permeability contrast (or heterogeneity) does not play a major role as \(G\) is increased further. Figure 12 illustrates the change in flow regime for the case when \(k_1:k_2=10:1\) as flow becomes affected by gravity and viscous fingers do not form any more. It can be seen that gravity effects can be aggravated as the permeability contrast between the layers and density contrast between the displaced oil and injected gas increase.
The other scenario that was analyzed is the case when the more permeable layer is in the bottom (as shown in Figure 3). The plots in Figure 13 show how gravity affects the efficiency of the displacement in terms of breakthrough time and recovery. The trends confirm that ultimately breakthrough is earlier and recovery decreases as gravity starts to dominate however there is a slight delay in breakthrough time and increase in recovery for cases when the permeability contrast is 1:2 and 1:10 at \( G=0.1 \). Such a behaviour can be explained by examining the corresponding concentration map shown in Figure 14 for the case when \( k_1:k_2=1:10 \). At \( G=0.01 \) the flow is viscous-dominated, however at \( G=0.1 \), viscous fingers are suppressed by a gravity tongue forming in the bottom layer and thus providing a better sweep. As \( G \) approaches 1, gravity tongues form in both upper and lower part of the reservoir and at \( G=10 \) the flow is fully controlled by gravity with no impact from the permeability contrast between the layers.

**Figure 13**: Plots of tertiary gas breakthrough time and incremental oil recovery at tertiary gas breakthrough as a function of gravity-viscous number for the two-layered reservoir with the more permeable layer in the bottom.

**Figure 14**: Concentration map at tertiary gas breakthrough for the two-layered system \((k_1:k_2=1:10)\). Red is the injected gas and blue is oil and water.

**SPE 10 Model 2 reservoir models: impact of heterogeneity and gravity**

The cases which have been investigated so far considered very simple permeability distributions and so the effects of gravity and heterogeneity are quite predictable and explainable. However, most reservoirs do not possess such simple permeability distributions; very often the heterogeneity pattern can be so complex that it becomes difficult to assess the impact of gravity and heterogeneity on displacement performance and the outcome of the analysis may not be as straightforward as for the cases which had been looked into previously. Having said that, the results derived from simpler cases will be used to analyze the results obtained from performing numerical simulations for heterogeneous SPE10 Model 2 layers, which present realistic cases with non-uniform permeability distribution.

Effective horizontal \((k_h)\) and vertical \((k_v)\) permeabilities for the different SPE10 Model 2 layers were calculated previously by Rashid et al. (2012) using a pressure-solver method. The geometric mean of these two was used as the effective permeability of the layer when calculating the gravity-viscous number \((G)\). Figure 15 shows the variation of \(k_v/k_h\) ratio by layers and it can be seen that the near-shore prograding Tarbert formation layers (from 1 to 35) are characterized by higher \(k_v/k_h\) values compared to more isotropic fluvial Upper-Ness formation layers (from 36 to 85). It should be noted that \(k_v/k_h\) ratio
is actually $k_v/k_h$ ratio, as the layers are originally horizontally oriented. They were placed vertically in order to capture as much variations of permeability heterogeneity and $k_v/k_h$ ratio as possible.

Figure 15: Plots of $k_v/k_h$ by SPE10 Model 2 layer number.

Such a distinction in $k_v/k_h$ values is expected to have an impact on displacement efficiency, which is confirmed when we compare the breakthrough times for secondary water injection and tertiary miscible gas injection ignoring gravity (Figure 16). The trends suggest that the breakthrough time of both water and gas is later for the layers from the Tarbert formation, which are characterized by higher $k_v/k_h$ ratio values. It should also be noted that there is a much wider variation of breakthrough time for the water injection than for the tertiary gas injection. This is because of the higher viscosity ratio in the gas injection.

Figure 16: Plots of secondary water breakthrough time and tertiary gas breakthrough time as a function of SPE10 Model 2 layer number.

Rashid et al. (2012) in their study of secondary gas injection showed that the vorticity-based heterogeneity index ($H_v$) (see Equation 6) correlates successfully with the gas breakthrough time and thus is able to quantify the heterogeneity. The results of the secondary water injection and tertiary miscible gas injection (ignoring gravity) simulations performed here also confirm the advantage and usefulness of this measure of heterogeneity. Figure 17 shows the very good correlations between water/gas breakthrough time and the heterogeneity index. They suggest that as the reservoir becomes more heterogeneous ($H_v$ close to zero), the breakthrough time is expected to be earlier. Similarly, as $H_v$ targets 1 (reservoir is more homogeneous), breakthrough time is delayed.

Figure 17: Plots of secondary water breakthrough time and tertiary gas breakthrough time as a function of vorticity-based heterogeneity index ($H_v$).
The impact of gravity on tertiary miscible gas injection is shown in Figure 18 for some selected layers, for various $H_v$ and $k_v/k_h$ values. The results confirm that as gravity becomes dominant, the breakthrough time gets earlier, although it is not as straightforward as in the homogeneous and two-layered systems. Three types of behaviour were identified:

1. these layers show the expected trends (Figure 18a), that is the gas breakthrough time is earlier as $G$ increases. They are characterized by relatively high values of $k_v/k_h$ and heterogeneity indices ($H_v$) (i.e. they are more homogeneous);
2. layers that exhibit a delay in breakthrough time as $G$ approaches 1 (Figure 18b), which is due to gravity suppressing the channeling through the heterogeneities, resulting in a more stable displacement front but ultimately displaying earlier breakthrough at $G=10$ as a result of the formation of a gravity tongue; these layers are also characterized by intermediate values of $k_v/k_h$ and heterogeneity ($H_v$);
3. layers (Figure 18c) that are characterized by a more or less constant breakthrough time over a wide range of $G$ ($1 \div 10$), before displaying a slightly earlier breakthrough time as $G$ approaches a value of 50. This group of layers are distinguished by relatively low values of $k_v/k_h$ and heterogeneity indices ($H_v$), suggesting that the displacement process for these layers is mostly affected by heterogeneity with very little impact from gravity even when $G$ number is increased.

The concentration maps shown in Figure 19 and 20 for layers 17 and 80 respectively best illustrate the processes taking place as $G$ number is increased. It can be seen that a clear gravity tongue is formed for layer 17 (Figure 19), but not in layer 80 (Figure 20), where the flow is still controlled by heterogeneity as $G$ number is increased.
How incremental oil recovery at tertiary gas breakthrough is related to the oil recovery at secondary water breakthrough at different $G$ numbers for the same layers is presented in Figure 21. Ideally, such a plot could have helped to predict oil recovery at gas breakthrough based on the production data obtained from secondary water injection, but as seen, there is unclear relationship between them. However, it can be clearly seen that oil recovery at gas breakthrough is significantly lower than the one at water breakthrough. This is due to earlier gas breakthrough as a result of higher viscosity and density contrast between the injected gas and displaced oil. It can also be noticed from the plot that increased gravity number ($G$) does not necessarily decrease the incremental oil recovery at gas breakthrough, for some layers it even has a boosting effect on recovery.
Figure 2 shows a 3D diagram and the corresponding surface plot of tertiary gas breakthrough time as a function of heterogeneity index ($H_v$) and the gravity-viscous number ($G$) obtained from numerical simulations of SPE10 Model 2 layers. It summarizes all the results from all the simulations performed and shows how gravity and heterogeneity affect the outcome of a tertiary miscible gas injection. It can be noticed that breakthrough time is relatively later (after 0.15 PVI) for layers with a higher heterogeneity index ($H_v$) and earlier for those with lower heterogeneity index ($H_v$). Another observation is that gravity is relatively unimportant, even at high gravity-viscous numbers ($G$), except in the more homogeneous layers.
Conclusions and recommendations

The quantification of the impact of permeability heterogeneity and gravity on tertiary miscible gas injection has been examined using the dimensionless gravity-viscous number \( G \) and vorticity-based heterogeneity index \( H_v \). Simulations were performed for homogenous, anisotropic, two-layered (with different locations of the more permeable layer) systems and layers from the very heterogeneous SPE10 Model 2 (Christie and Blunt 2001). This was achieved by performing simulations of secondary water injection followed by First Contact Miscible (FCM) tertiary gas injection for different gravity-viscous numbers \( G \). The effective permeability of each system when calculating \( G \) was defined as the geometric mean of effective vertical \( k_v \) and horizontal \( k_h \) permeabilities.

Displacement performance indicators, namely tertiary gas breakthrough time (PVI) and incremental oil recovery at tertiary gas breakthrough (PV) were obtained and were used in conjunction with the dimensionless gravity-viscous number \( G \) to determine the flow regimes present when analyzing the cases of anisotropic homogeneous and two-layered systems. The investigation indicated that generally the flow is dominated by viscous effects when \( G<0.1 \) and gravity-dominated when \( G>1 \) and the effects of gravity are most pronounced when the values of \( k_v/k_h \) for the homogeneous system and the permeability contrast for the two-layered system is the highest. It was also confirmed that viscous-dominated cases are characterized by delayed tertiary gas breakthrough times and higher recoveries, while gravity-dominated cases exhibit earlier breakthrough times and lower recovery indicators. For a case of the two-layered system when the more permeable layer is in the bottom with lower permeability contrasts between the layers, there is a delay in gas breakthrough time at \( G=1 \), which is the result of viscous forces being gradually suppressed by gravity forces in the bottom layer and thus a better sweep is achieved.

The analysis of the simulation performed on SPE10 Model 2 heterogeneous layers were carried with the help of an additional measure, the vorticity-based heterogeneity index \( H_v \) introduced by Rashid et al. (2012). The advantage of using this index was shown with the very good linear correlation with secondary water injection and tertiary gas injection breakthrough times, demonstrating its ability to rank the impact of heterogeneity on recovery. As for the study of impact of gravity for these layers, it was shown that as gravity increases, the behaviour is not as straightforward in the homogeneous and two-layered systems. Some layers showed the trends expected — gas breakthrough becomes earlier as \( G \) increases. These layers were characterized by relatively high values of \( k_v/k_h \) and heterogeneity index \( H_v \). Another group exhibits a delay in breakthrough time as \( G \) approaches \( 1 \) due to the gravity suppressing viscous fingers resulting in a better sweep, but ultimately display earlier breakthrough time at \( G=10 \); these layers are characterized by intermediate values of \( k_v/k_h \) and heterogeneity index \( H_v \). The last group is characterized by generally later breakthrough times over a wide range of \( G \), before displaying slightly earlier breakthrough time at higher values of \( G \); these are distinguished by relatively low values of \( k_v/k_h \) and heterogeneity index \( H_v \), implying that the displacement process for these layers is mostly heterogeneity-driven. The behaviour of the second and the third groups can be related to the one that was observed in the two-layered case with the more permeable layer in the bottom at the ratio of layer permeabilities of \( 1:2 \) and \( 1:10 \), suggesting that these layers are effectively fining upwards.

It was also shown that incremental oil recovery at tertiary gas breakthrough is much lower than oil recovery at secondary water breakthrough, which is due to earlier gas breakthrough as a result of higher viscosity and density contrast between the injected gas and the displaced oil. Although additional oil is recovered, in real life earlier gas breakthrough means recycling of significant amount of gas. It was also seen that incremental oil recovery at gas breakthrough does not always decrease as gravity number \( G \) is increased.

A 3D diagram of tertiary gas breakthrough time as a function of heterogeneity index \( H_v \) and the gravity-viscous number \( G \) was constructed based on the obtained results of SPE10 Model2 simulations. Further work is needed to confirm whether this diagram is the same for other types of heterogeneities. Nevertheless, such a diagram is suggested to be used as a fast prediction tool of the efficiency of the proposed tertiary miscible gas injection scheme or any other EOR process.

Nomenclature

\[
\begin{align*}
c & \quad \text{Concentration} \\
D & \quad \text{Dispersion tensor} \\
G & \quad \text{Gravity-viscous number} \\
g & \quad \text{Acceleration due to gravity} \\
H & \quad \text{Reservoir height} \\
H_v & \quad \text{Vorticity-based heterogeneity index} \\
k & \quad \text{Permeability term} \\
k_1 & \quad \text{Permeability of top layer} \\
k_2 & \quad \text{Permeability of bottom layer} \\
k_e & \quad \text{Effective horizontal permeability} \\
k_r & \quad \text{Effective vertical permeability} \\
k_{re(max)} & \quad \text{Maximum relative permeability of the reservoir rock to oil} \\
k_{rw(max)} & \quad \text{Maximum relative permeability of the reservoir rock to water} \\
L & \quad \text{Reservoir length} \\
M & \quad \text{Mobility ratio} \\
r & \quad \text{Location vector} \\
R_L & \quad \text{Aspect ratio} \\
v & \quad \text{Injection rate} \\
V_d & \quad \text{Displacement vorticity} \\
\mu_o & \quad \text{Oil viscosity} \\
\mu_g & \quad \text{Gas viscosity} \\
\mu_w & \quad \text{Water viscosity} \\
\Delta p & \quad \text{Difference between oil and gas densities} \\
\varphi & \quad \text{Reservoir porosity}
\end{align*}
\]
References


Christie, M. A., Jones, A. D. W., Muggeridge, A. H.: *Comparison between laboratory experiments and detailed simulations of unstable miscible displacements influenced by gravity*. *North Sea Oil and Gas Reservoirs II*, Graham and Trotman, London (1990), 245-300


## Appendix A – Milestones in literature review

<table>
<thead>
<tr>
<th>Paper</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>API, Secondary recovery of oil in US (160-174)</td>
<td>1950</td>
<td>“The Prediction of Oil Recovery by Waterflood”</td>
<td>H. Dykstra, R.L. Parsons</td>
<td>First to propose a measure of heterogeneity correlated against waterflood performance known as the Dykstra-Parsons coefficient, which is a dimensionless measure of sample variability of static permeability data.</td>
</tr>
<tr>
<td>Production Monthly, vol. 15, no 9 (9–12)</td>
<td>1950</td>
<td>“The Variation of Waterflood Performance with Variation in Permeability Profile”</td>
<td>J. Schmalz, H. Rahme</td>
<td>Developed a measure known as Lorenz coefficient for characterizing the static permeability distribution in a reservoir by estimating recovery using the flow capacity of a layer as well as its thickness.</td>
</tr>
<tr>
<td>SPE 450</td>
<td>1963</td>
<td>“A Method for Predicting the Performance of Unstable Miscible Displacement in Heterogeneous Media”</td>
<td>E. Koval</td>
<td>First to develop a dynamic index known as Koval’s heterogeneity factor which accounts for the effects of viscosity differences, channelling and longitudinal dispersion on the efficiency of unstable miscible displacements.</td>
</tr>
<tr>
<td>SPE 18438</td>
<td>1990</td>
<td>“Extensions to Dietz Theory and Behaviour of Gravity Tongues in Slightly Tilted Reservoirs”</td>
<td>F.J. Fayers, A.H. Muggeridge</td>
<td>Developed an improvement on the Dietz’s equation and a new gravity-viscous dimensionless number was introduced to investigate the onset of viscous fingering.</td>
</tr>
<tr>
<td>SPE 27833</td>
<td>1997</td>
<td>“Scaling of Multiphase Flow in Simple Heterogeneous Media”</td>
<td>D. Zhou, F.J. Fayers, F.M. Jr Orr</td>
<td>Dominant flow regimes in a reservoir were identified at various conditions by the help of three dimensionless numbers, which are gravity-viscous ratio, capillary-viscous ratio and shape factor.</td>
</tr>
<tr>
<td>SPE 78349</td>
<td>2002</td>
<td>“Tertiary Miscible Gas Injection in the Alwyn North Brent Reservoirs”</td>
<td>L.J. Burns, G.J. Richardson, R.N. Kimber</td>
<td>Analysed the performance of tertiary miscible gas injection in Alwyn oilfield located in the North. Mostly stressed on geological specifications of the reservoir, which was the dominant factor in selecting the right strategy for the tertiary miscible gas injection.</td>
</tr>
<tr>
<td>SPE 124625</td>
<td>2009</td>
<td>“A Robust Measure of Heterogeneity for Ranking Earth Models: The F PHI Curve and Dynamic Lorenz Coefficient”</td>
<td>G.M. Shook, K.M. Mitchell</td>
<td>Used streamline time of flight and volumetric flow rate information from simulation to obtain a flow capacity diagram and sweep efficiency history from which five measures of heterogeneity were obtained. These were then used to establish that the Lorenz coefficient determined from dynamic data is the single best measure of heterogeneity.</td>
</tr>
<tr>
<td>SPE 135125</td>
<td>2010</td>
<td>“Quantifying the Impact of Permeability Heterogeneity on Secondary-Recovery Performance”</td>
<td>B. Rashid, A. Bal, G. Williams, A.H. Muggeridge</td>
<td>Developed a new and improved heterogeneity index that uses the shear-strain rate of the single phase velocity field to characterize the permeability heterogeneity in terms of its impact on performance of the reservoir. Comparisons with the Dykstra-Parsons coefficient and the Dynamic Lorenz coefficient were run to see the benefits of the new heterogeneity index.</td>
</tr>
<tr>
<td>Computational Geosciences, vol. 16, no. 2 (409- 422)</td>
<td>2012</td>
<td>“Using Vorticity to Quantify the Relative Importance of Heterogeneity, Viscosity Ratio, Gravity and Diffusion on Oil Recovery”</td>
<td>B. Rashid, A. Bal, G. Williams and A.H. Muggeridge</td>
<td>Developed the vorticity-based heterogeneity index which measures the impact of permeability and porosity heterogeneity on reservoir performance. This heterogeneity index was then used to analyse the relative impacts of heterogeneity, buoyancy effects, mobility ratio and dispersion on reservoir performance during first contact miscible gas injection.</td>
</tr>
<tr>
<td>SPE 165298</td>
<td>2013</td>
<td>“EOR: Challenges of Translating Fine Scale Displacement into Full Field Model-Part 2”</td>
<td>J. Moreno, S. Flew, O. Gurpinar</td>
<td>Investigated the challenges related to modelling the fine scale EOR displacements and their application to the full field scale. The study is mainly concentrated on the effects of reservoir heterogeneity on the performance of EOR injection processes together with resolution of the model for both miscible and immiscible displacements.</td>
</tr>
</tbody>
</table>
Appendix B – Critical literature reviews

SPE 450 (1963)

A Method for Predicting the Performance of Unstable Miscible Displacement in Heterogeneous Media

Authors: Koval, E.

Contribution: Developed a dynamic index known as Koval’s heterogeneity factor which accounts for the effects of viscosity differences, channelling and dispersion on the efficiency of unstable miscible displacements.

Objective: To develop a measure (K-factor) able to predict recovery and solvent fractional flow as a function of number of pore volumes of solvent injected.

Methodology: K-factor was derived analytically on the assumption that a single parameter can be used to characterize the dependency of recovery and solvent cut on the viscosity ratio, which is known as the effective viscosity ratio. Effect of heterogeneity was incorporated by back calculating K-factor from experimental data at varying viscosity ratios.

Conclusions:
- K-factor method is a satisfactory prediction tool of the interaction of reservoir heterogeneity and unstable miscible displacements.
- Relationship between the K-factor and the Dykstra-Parsons permeability variation coefficient is observed which implies that prediction of unstable miscible displacement processes in heterogeneous reservoirs is possible.

Comments: Useful for understanding on how to take into account heterogeneity while predicting unstable miscible displacements, however it is computationally complex to use for quick characterization of different reservoir models.
SPE 18438 (1990)

*Extensions to Dietz Theory and Behavior of Gravity Tongues in Slightly Tilted Reservoirs*

**Authors:** Fayers F.J., Muggeridge A.H.

**Contribution:** Extended Dietz theory and used it to investigate the effects of viscous fingering using a new dimensionless viscous-gravity number.

**Methodology:** The Dietz equation was modified by solving the equation of Sheldon and Fayers. A new viscous-gravity dimensionless number was then derived which was used to investigate the effects of viscous fingering and breakdown of segregated flow. Black oil simulator was used in the process of performed study.

**Conclusions:**
- The extension of the Dietz theory was shown as important and useful.
- The new viscous-gravity dimensionless number is able to quantify gravity dominated flow regimes.

**Comments:** Significant improvement to the Dietz equation was introduced and a new functional dimensionless number was proposed, but the applicability of this extension to heterogeneous reservoirs is not very clear.
**SPE 78349 (1992)**

*Tertiary Miscible Gas Injection in the Alwyn North Brent Reservoirs*

**Authors:** Burns L.J., Richardson G.J., Kimber R.N.

**Contribution:** Good example of successful industrial application of tertiary miscible gas injection.

**Objective:** Analysis of the performance of tertiary miscible gas injection in Alwyn oilfield located in the North Sea and improvement of the microscopic and macroscopic sweep by continuous optimization of the process.

**Methodology:** Mostly stressed on geological specifications of the reservoir, which was the dominant factor in selecting the right strategy for the tertiary miscible gas injection. For example, they decided to isolate highly permeable upper Tarbert 3 zone and allow better sweep for lower Tarbert and Ness channel sands in order to prevent gravity override. In addition, intensive reservoir monitoring was carried out, so that performance changes could be quickly identified and adjustments applied.

**Conclusions:**
- Tertiary gas injection of 1.63 Gsm³ in 2.5 years resulted in additional 1.5 million bbl of incremental oil recovery;
- According to simulation studies, good miscibility process is achieved where the gas contacts the oil for both macroscopic and microscopic scales;
- Early gas breakthrough cases in some wells show that it is extremely important to have a detailed knowledge of the reservoir geology.

**Comments:** Useful piece of work on understanding how such an EOR method is realized in real life and how to account for heterogeneity.
SPE 27833 (1997)

Scaling of Multiphase Flow in Simple Heterogeneous Media

Authors: Zhou D., Fayers F.J., Orr F.M. Jr.

Contribution: Dominant flow regimes in a reservoir were identified at various conditions by the help of three dimensionless numbers, which are gravity-viscous ratio, capillary-viscous ratio and shape factor.

Objective: Develop a workflow able to determine flow regimes occurring at various conditions in a reservoir.

Methodology: Three dimensionless numbers characterizing different flow regimes were obtained using inspectional analysis: gravity-viscous ratio, capillary-viscous ratio and shape factor. These dimensionless numbers were then used to solve and identify flow regions for both miscible and immiscible displacements. Flow in fractured reservoirs with appropriate boundaries for transition between regions was specified as well.

Conclusions:
- The dimensionless gravity-viscous and capillary-viscous ratios can be used to identify different flow regions in heterogeneous porous media.
- Performance of miscible displacement can be very complex due to the fact that the gravity number can have a significant impact on whether the flow is viscous or gravity dominated.
- Capillary-gravity force ratio determines recovery mechanism in fractures, so it is important to define flow regions in the simulation of fractured systems.

Comments: Crucial work in understanding the development of dimensionless groups and selection of flow regime boundaries between regions. The result of the study is the 3D plot which explained how flow regimes change at different dimensionless numbers. This study, however, did not take into account the impact of reservoir heterogeneity.
SPE 124625 (2009)

Robust Measure of Heterogeneity for Ranking Earth Models: the F PHI Curve and Dynamic Lorenz Coefficient

Authors: Shook G.M., Mitchell K.M..

Contribution: Developed the dynamic Lorenz coefficient as a new method for estimating heterogeneity in Earth models.

Objective: Determine the best measure of heterogeneity from derived 5 measures of heterogeneity on the basis of streamline simulation.

Methodology: Used streamline time of flight and volumetric flow rate information from the simulation to come up with a flow capacity and sweep efficiency history diagram from which five measures of heterogeneity were obtained. The derived heterogeneity measures were then used against 450 models that were established using a wide range of Dykstra-Parsons coefficient, correlation length and two different well patterns.

Conclusions:
- Simple method for calculation of flow geometry from F-Φcurves using streamline simulation was presented;
- The new method only requires a few timesteps of a given streamline model to achieve steady state conditions, so heterogeneity can be assessed very quickly;
- It was found that the Lorenz coefficient determined from dynamic data is the single best measure of heterogeneity.

Comments: Good and robust method of quantifying reservoir heterogeneity, however Rashid et al. (2012) showed that it was not able to correlate against performance indicators for SPE10 Model 2 (Christie and Blunt 2001) heterogeneous layers.
SPE 135125 (2010)

Quantifying the Impact of Permeability Heterogeneity on Secondary Recovery Performance

Authors: Rashid B, Bal A., Williams G., Muggeridge A.H.

Contribution: Developed a new and improved measure based on the shear-strain rate of the single phase Darcy velocity field able to quantify reservoir heterogeneity for unstable miscible and immiscible displacements.

Objective: To obtain a new measure able to capture heterogeneity for secondary recovery performance.

Methodology: Introduced new heterogeneity index using the shear-strain rate of the single-phase velocity field and used this index to assess the impact of heterogeneity on SPE10 Model 2 layers (Christie and Blunt 2001) by performing simulations to predict performance and compared results with those of traditional heterogeneity indices, such as Dykstra-Parsons and dynamic Lorenz coefficients.

Conclusions:
- New heterogeneity index was able to rank layers by heterogeneity for miscible and immiscible displacements;
- The shear-rate based heterogeneity index correlated better against performance indicators (gas breakthrough time and recovery at 1 PVI) than the Dykstra-Parsons and dynamic Lorenz coefficients;

Comments: Good tool to predict reservoir performance for unstable miscible and immiscible displacements and ranking heterogeneity.
Computational Geosciences (2012) (volume 16/ number 2/ pages 409-422)

Using Vorticity to Quantify the Relative Importance of Heterogeneity, Viscosity Ratio, Gravity and Diffusion on Oil Recovery

Authors: Rashid, B., Bal, A., Williams, G.J.J. and Muggeridge, A.H.

Contribution: Developed the vorticity-based heterogeneity index which is able to quantify the impact of heterogeneity on reservoir performance. It was then used to analyze the relative impacts of heterogeneity, buoyancy effects, mobility ratio and dispersion on reservoir performance during FCM (first contact miscible) gas injection.

Objective: To investigate under which flow conditions reservoir heterogeneity becomes more important than other physical processes.

Methodology: Vorticity-based heterogeneity index was developed using the vorticity of the velocity displacement as suggested originally by Heller (1966). Various simulations of FCM gas/solvent injection were performed heterogeneous layers that were taken from geologically realistic SPE10 Model 2 (Christie and Blunt 2001). Performance indicators (gas breakthrough time and recovery at 1 PVI) were used to quantify the relative impacts of various physical effects.

Conclusions:
• The new vorticity-based heterogeneity index varies from 0 to 1; the larger the value, the more homogeneous the reservoir;
• Highly heterogeneous layers are generally characterized by earlier breakthrough and lower recovery;
• At adverse viscosity ratios, viscous fingering and channelling of gas result in early breakthrough and low recovery, thus effect of heterogeneity is diminished;
• When gravity dominates flow, dependence of breakthrough time and recovery on reservoir heterogeneity is minimal.

Comments: Important work on the use of vorticity-based heterogeneity index and understanding of different physical processes which dominate the displacement in a reservoir.
SPE 165298 (2013)

*EOR: Challenges of Translating Fine Scale Displacement into Full Field Models – Part 2*

**Authors:** Moreno J., Flew S., Gurpinar O.

**Contribution:** Investigated the challenges related to modelling the fine scale EOR displacements and their application to the full field scale model. The study is mainly concentrated on the effects of reservoir heterogeneity on the performance of EOR processes together with resolution of the model for both miscible and immiscible displacements.

**Objective:** To determine the scale of the impact of heterogeneity modeling resolution on EOR processes.

**Methodology:** Simulation studies were performed on core-scale models for coarsening up, fining up and randomly allocated permeability cases. The same process was repeated for scaled up models, i.e. representing field scale reservoir models. Grid sizes and EOR agents were varied and the results were compared.

**Conclusions:**
- Reservoir description of high resolution is essential to increase the predictive power of an EOR numerical model;
- Improper application of coarse scale models to analyse EOR processes may dramatically over predict the recovery;
- Fine scale models both for core and field cases can give a much better prediction of contacted and displaced oil.

**Comments:** Useful to understand the effect of model heterogeneity resolution and transitioning from core scale to field scale on EOR processes.
Appendix C – Software usage specifications

The simulation works were performed using MISTRESS, a Fortran-based software developed originally by Bateson J. (1985). It was modified by Christie M.A (1989) and then by Rashid B. The input data file extension is *.dat and the sample is presented below. For layered systems, the permeability data is saved in a *.prn file, where vertical and horizontal permeabilities can be entered. The output *.hist file contains the results of the performed simulation such as oil, gas and recoveries and fractional flows. The *.vtk file contains the concentrations, pressure, saturations, horizontal and vertical permeabilities, velocities and the horizontal and vertical vorticities contour maps.

```
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*SOLVER BANDP
VISCW   1.0
VISCO   2.0
VISCS   0.1
DENSITYS 1.0
DENSITYO 1.0
THETA 1.0 ! IMPLICITNESS PARAM = 1.0 FOR PC AND DIFFUSION TERMS
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SATDIST
CINIT  0.00
SWCRIT  0.15
SORSDL  0.2
KROSWC  1.0
KRWSOR  1.0
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*READPERM
READPFIL
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MODERANX 1 5427896
*READPERM
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*MODSINIT 1 10 1 1 0.8
*       GX   GY
GRAV  0.0  -1.0
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TOUT  0.1
TOUT  0.2
TOUT  0.3
TOUT  0.4
TOUT  0.5
TOUT  0.6
TOUT  0.7
TOUT  0.8
QINJ  1.0
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*Run 1-3 FWINJ 0.5  2.0
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FRQRT 5000
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WELL 1 1 1 NY INJN                          1.0
* BLX BLY TRX TRY TYPE  BHP  PI
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* CHANGEVT 0.05
FCTS
FCTC
* Ask for pseudos for flow in x-direction.
* ------------------------------------------------
* Direction No of. Output frequency
*       grid blocks (ie every 50 timesteps)
* ------------------------------------------------
*XPSUEDO 1  50
*XPSUEDO 2  50
*XPSUEDO 4  50
* Ask for output so we can generate effective relative permeabilities
* at a later date.
* ------------------------------------------------
* Direction Output frequency Fluid (WATER or SOLV)
* ------------------------------------------------
*EFFREPX  50      WATER
*READREG
OUTLEVEL 1
FULLSIZE
*DTMOVIE 1.0E-03 WATER
END