The Role of Diffusion for Non-Miscible Gas Injection into a Fractured Reservoir

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Abstract
To improve oil recovery from pervasively fractured reservoirs, gas injection can be considered. In such reservoirs, the fractures typically provide the flowpaths but contain a limited amount of the oil whereas the matrix often has orders of magnitude lower permeabilities but contains the oil.

To improve oil recovery from such reservoirs, gas/oil gravity drainage can be applied. In this process, a gravity stable displacement can be achieved.

If gas is injected which is not in equilibrium with the oil, the non-equilibrium gas components diffuse from the fracture system into the matrix and the components of the oil diffuse towards the fracture system. This results in a modification of the properties of the oil affected by diffusion and gravity drainage rates accordingly.

The effects of non-equilibrium gas injection into a pervasively fractured reservoir were studied at the example of an Austrian reservoir. This type of gas injection results in a zone of decreased oil viscosity for gases such as CO₂ and CH₄ at the interface of the gas and the oil in the matrix. This zone of lower oil viscosity increases the gas/oil gravity drainage rates.

The results show that the effect of diffusion can increase cumulative oil production up to 25 % compared with a case neglecting the effect of diffusion. The effect of diffusion could be determined for various parameters such as permeability, porosity, fracture spacing and matrix block height. While for some of the parameters, the effect of diffusion scales with the square root of time (e.g. permeability), for others an exponential relationship has been determined (fracture spacing).

The results derived for the example reservoir can be used more generally to screen whether the effect of diffusion should be incorporated into reservoir studies concerning non-equilibrium gas injection and how large the error could be in case that diffusion is neglected.
Introduction

Oil recovery from pervasively fractured reservoirs is challenging due to the often large contrast in permeability of the fractures and the matrix. Frequently, the matrix of such reservoirs contains the oil while the fractures provide the flowpaths. In such reservoirs, oil production can be improved by making use of gas/oil gravity drainage (e.g. O’Neill 1988, Novinpour et al. 1994, Saidi 1996, Eikmans and Hitchings 1999).

Different zones can be distinguished in reservoirs which are produced by using gas/oil gravity drainage (Saidi 1975):

1. Gas invaded zone: in this zone, the matrix is oil filled but partially gas invaded. The fractures are gas filled. The main processes occurring in this zone are gas/oil gravity drainage and diffusion. The oil is flowing in the matrix down towards the oil rim.
2. Oil rim: this zone is located between the current gas/oil and water/oil contact in the fractures. The fractures and matrix are oil filled. Oil is entering the fractures and flowing toward the wells.
3. Water invaded zone: This zone is characterised by the fractures being water filled and the matrix oil bearing but water invaded. The main processes are water/oil gravity drainage and water imbibition.

The different zones and processes are illustrated in Figure 1.

**Figure 1-Schematic diagram of a pervasively fractured reservoir with a large permeability contrast between fractures and matrix. The fractures are connected in the third dimension. Fractures are gas filled above the current gas/oil contact (GOC) while the matrix is still oil filled but gas invaded. The oil is flowing vertically downwards through the matrix in the gas invaded zone and then through the fracture system to the wells.**
For oil recovery of such reservoirs by gas injection, the performance of the gas invaded zone is essential. In this zone, the fractures are gas filled and the matrix is gas invaded. Experiments and theoretical concepts showed that in this zone, the oil is flowing down in the matrix (e.g. Saidi et al. 1979, Hagoort 1980, Hori et al. 1990, Labastie 1990, Firoozabadi and Ishimoto 1994).

The change in oil saturation and oil flow in the gas invaded zone neglecting capillary forces is shown in Figure 2. Initially, the matrix is completely oil filled. Due to production and/or gas injection, a gas/oil contact in the fractures is generated. Gas invades into the matrix.

Two periods can be distinguished for such reservoirs, plateau gravity drainage prior to gas breakthrough and the continuously reducing oil production after gas breakthrough at the bottom of the matrix (“after drainage period”) (Saidi et al. 1979, Hagoort 1980). The plateau production is the “free-fall gravity drainage rate” governed by the density difference of oil and gas, matrix permeability and oil viscosity. Note that in this paper, gas breakthrough refers to gas reaching the bottom of the initially oil filled matrix.

![Figure 2-Development of saturation profiles in a matrix block for gas/oil gravity drainage conditions. Initially, the block is oil filled. Gas invades the block. Until the gas reaches the bottom of the block (t=\(t_{BT}\)), the maximum gravity drainage rate can be achieved. Then, the oil rate declines (“after drainage”). The diagram shows the oil saturation (\(S_o\)) versus depth (\(z\)) for different times (\(t_0, t_1, t_2, \ldots\)). \(t_{BT}\) refers to the time of gas breakthrough at the bottom of the block.](image)

If an impermeable layer is hampering the flow of oil in the matrix, the ultimate recovery is reduced due to the capillary hold-up. The maximum oil production rate is reduced if the block height is small compared with the fracture spacing (Clemens and Wit 2001).

Oil recovery from fractured reservoirs can be improved by injection of non-equilibrium gases. In such cases, the gas fills the fractures and components are exchanged by diffusion.
with the oil containing matrix. The driving force is the difference in concentration of the components in the fracture and matrix. Each component has a different diffusion coefficient and concentration.

A number of laboratory experiments have been performed indicating the importance of diffusion (e.g. Thiebot and Sakthikumar 1991, Morel et al. 1993, Le Romancer et al. 1994, Lenormand et al. 1998, Hatiboglu and Babadagli 2004, Karimaie et al. 2007, Torabi and Ashghari 2009, Moortgat et al. 2010). Based on the result of laboratory experiments and on fluid flow dynamics, several additional articles investigating the effect of diffusion in fractured reservoirs have been published (e.g. Grogan and Pinczewski 1987, da Silva and Belery 1989, Coats 1989, Uleberg and Hoier 2002, Alavian and Whitson 2009).

In this paper, the role of diffusion is investigated for fractured reservoirs produced by gas/oil gravity drainage. Similar to Verlaan and Boerrigter 2006 and Kazemi and Jamialahmadi 2009, a reservoir with a large contrast in matrix and fracture permeability, with low effective fracture porosity and higher matrix porosity and a constrained gas production rate is investigated.

In the following section, the field case and simulation model is introduced. Then, the simulation results are described followed by a discussion and summary section.

Field case

The Schönkirchen Tief field in Austria has been produced for more than 50 years. The oil originally in place was 19 million m³ of light oil. The field consists of fractured dolomite with high fracture permeabilities (500 md to 7,000 md). The reservoir depth is 2470 m subsea (mSS) at the top of the structure and the original oil water contact is at 2740 mSS (for more details see de Kok and Clemens 2009).

The field is at end of the lifetime of oil production. Owing to the good permeability, reasonable size of the field and high relief, two alternative development strategies to continuing oil production are investigated: transforming the field to high performance Underground Gas Storage (UGS) and injection of CO₂ for geological storage. In both cases, additional oil might be recovered (e.g. Burke 1960, Spivak et al. 1989 and Beliveau and Payne 1991) by producing oil downdip of the high relief reservoir and gas injection in a crestal position.

In the case of gas injection for UGS, the injected gas consists of methane with very few other components. The equilibrium gas (solution gas) of the oil in the reservoir, however, contains heavier components. Hence, the injected gas is not in equilibrium with the reservoir oil.

For the CO₂ and methane injection, the gas is not miscible with the reservoir oil but will lead to exchange of components.
To investigate the effects of the injected gas (methane or CO\textsubscript{2}) which is not at equilibrium with the reservoir oil, a simplified model has been generated. The details of the model are described in the following section.

**Simulation model**

The model was populated with reservoir and fluid parameters similar to the properties of the Schönkirchen Tief Field.

It consisted of 1 cell in y-direction, 30 cells in x-direction and 150 cells in z-direction. The model included a fracture system at the edge (first cell in x-direction) and a matrix.

The base model had an extension of 3 m in y-direction (half fracture distance of 1.5 m). The vertical extension was 150 m. The initial pressure was 276 bar at the crest (similar to the current reservoir pressure). The oil viscosity at initial conditions was 0.85 cP. The oil density was 888 kg/m\textsuperscript{3} and the density of the CO\textsubscript{2} 608 kg/m\textsuperscript{3}.

A homogeneous model was used. The matrix permeability was 5 mD and the matrix porosity 6.2 %. The fracture intrinsic permeability was 100 D and fracture porosity 100 %. For the matrix, a critical gas saturation of 0.01 %, gas endpoint of the relative permeability of 0.8 and Corey exponent of 2 was introduced, for the oil a residual oil saturation (towards gas) of 6 % and Corey exponent of 3.3. The connate water saturation was 25 %. For the fractures, straight line relative permeability curves were used.

A nine components Equation of State was generated. The reservoir was initialized with the matrix oil filled and the gas/oil contact in the fracture close to the bottom of the model. The diffusion coefficients were calculated using the da Silva and Belery (1989) method. Table 2 summarises the diffusion coefficients of the various components in oil and gas.

**Table 1- Composition of the reservoir fluid at 103 °C and 231 bar**

<table>
<thead>
<tr>
<th>Components</th>
<th>Liquid composition</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>0.396</td>
</tr>
<tr>
<td>C2</td>
<td>0.012</td>
</tr>
<tr>
<td>C3</td>
<td>0.005</td>
</tr>
<tr>
<td>C4 – C6</td>
<td>0.015</td>
</tr>
<tr>
<td>Pseudo 1 (C7 – C15)</td>
<td>0.186</td>
</tr>
<tr>
<td>Pseudo 2 (C16 – C29)</td>
<td>0.177</td>
</tr>
<tr>
<td>Pseudo 3 (C30+)</td>
<td>0.200</td>
</tr>
<tr>
<td>N2</td>
<td>0.009</td>
</tr>
<tr>
<td>CO2</td>
<td>0.002</td>
</tr>
</tbody>
</table>
Figure 3-Schematic diagram of the base case simulation model showing the high permeable fracture at the edge and the matrix. The wells were completed at the crest and bottom. Initially, the matrix is completely oil filled and the fracture is gas filled almost to the bottom. The lowermost cells of the fracture and the fracture along the bottom are initially oil filled.

Table 2-Diffusion coefficients of the species in oil and gas.

<table>
<thead>
<tr>
<th>Component</th>
<th>Diffusion coefficient in m²/s in gas</th>
<th>Diffusion coefficient in m²/s in oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1</td>
<td>6.15E-09</td>
<td>1.10E-10</td>
</tr>
<tr>
<td>C2</td>
<td>4.54E-09</td>
<td>9.90E-11</td>
</tr>
<tr>
<td>C3</td>
<td>4.45E-09</td>
<td>7.83E-11</td>
</tr>
<tr>
<td>C4 – C6</td>
<td>3.54E-09</td>
<td>5.82E-11</td>
</tr>
<tr>
<td>Pseudo 1 (C7 – C15)</td>
<td>2.46E-09</td>
<td>3.84E-11</td>
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<tr>
<td>Pseudo 2 (C16 – C29)</td>
<td>1.61E-09</td>
<td>2.86E-11</td>
</tr>
<tr>
<td>Pseudo 3 (C30+)</td>
<td>1.26E-09</td>
<td>2.64E-11</td>
</tr>
<tr>
<td>N2</td>
<td>7.73E-09</td>
<td>1.37E-10</td>
</tr>
<tr>
<td>CO2</td>
<td>5.97E-09</td>
<td>9.68E-11</td>
</tr>
</tbody>
</table>

In the following section, the results for the base case are described. Then, various parameters are modified and the effect on the oil production is investigated.
Base case

No diffusion

First, simulations without diffusion were performed. In the base case, the injected gas was CO₂. For the production well, an oil rate constraint of 0.0875 m³/d and gas rate constraint of 142 m³/d and minimum flowing bottomhole pressure of 100 bar was applied. The gas injection was set at a high gas injection rate constraint to ensure constant pressure conditions in the reservoir.

Figure 4 shows that a zone of gas invasion into the matrix develops from the top of the block downwards. At the interface of the gas and oil, an area of reduced oil viscosity is present (Figure 4). The oil with the initial viscosity comes in contact with the injected CO₂. This results in a decrease in oil viscosity by CO₂ moving into the oil (blue colours in Figure 4 on the left). Behind the front, the oil saturation is decreasing and the CO₂ strips lighter components out of the oil leading to an increase in oil viscosity even above the oil viscosity at initial conditions.

![Figure 4: Gas saturation and oil viscosity in the reservoir model without diffusion after 850 days. The gas invades at the top of the block (left). A zone of reduced oil viscosity develops at the gas/oil interface (right). The grey colour in the Figure on the right side indicates oil viscosities above 0.79 cP](image)

The oil production rate and gas/oil ratio (GOR) is shown in Figure 5. Initially, the oil production well is constraint by the maximum oil production rate. Once gas coned through the fracture to the well, the gas constraint is active. The GOR stays constant until the gas saturation reaches the bottom of the matrix block. The corresponding rate prior to gas breakthrough at the bottom of the matrix block is the “free-fall gravity drainage rate”. After gas breakthrough, the oil rate decreases (“after drainage rate”). The plateau gravity drainage rate is given by:
\[ Q = A k_z \lambda_o \Delta \rho_{og} g \]  

(1)

With the cross sectional area \( A \), vertical permeability \( k_z \), oil mobility \( \lambda_o \) and density difference between oil and gas \( \Delta \rho_{og} \) and gravity constant \( g \).

**Figure 5**-Oil production rate (red) and gas/oil rate (green) for the base case without diffusion.

**With diffusion**

The viscosity of the oil in the matrix develops differently if diffusion is included in the simulation. For this case, \( \text{CO}_2 \) invades the matrix not only from the top but also through the vertical plane of the fractures (**Figure 6**) since compositional gradients are present. The oil viscosity is reduced along the vertical fracture planes as well.
Figure 6-Gas saturation and oil viscosity in the reservoir model with diffusion after 850 days. The gas invades at the top of the block and along the fracture plane (left). The zone of reduced oil viscosity is extending vertically due to the diffusion into the block (right).

The cumulative oil production with and without diffusion is depicted in Figure 7. With time, the difference in cumulative oil production is increasing. Plotting the difference of the cumulative oil production with and without diffusion shows a good match if the difference is plotted versus the square root of time (Figure 8).

Figure 7-Cumulative oil production with (blue) and without (pink) diffusion. With time, the difference in cumulative oil production is increasing.
The good fit of the difference of cumulative oil production with and without diffusion versus the square root of time is expected for diffusion processes. The difference in cumulative oil production with and without diffusion originates from the injected gas diffusing from the gas/oil interface into the oil. Hence, this difference is related to the diffusion length. A zone of lower oil viscosity and higher gravity drainage rates accordingly is generated. The area of enhanced gravity drainage leads to accelerated oil production compared with the case without diffusion.

In such processes, the diffusion length can be estimated using:

$$L = \sqrt{Dt}$$  \hspace{1cm} (2)

With the distance the components are travelling $L$, diffusion coefficient $D$ and time $t$. As can be seen in equation 2, the diffusion length which corresponds to the difference in cumulative oil production with and without diffusion in Figure 8 is dependent on the square root of time.

The different zones which are developing for injection of non-equilibrium gases are illustrated in Figure 9 and described below:

Zone 1: Gas filled fracture: oil components reaching this area are produced by the production wells.
Zone 2: Gas invaded zone: CO$_2$ diffuses into the matrix. The oil in this area already moved downwards. Oil is at residual oil saturation (no gravity drainage) and components of the oil are stripped out by CO$_2$ and diffuse towards the fracture. The oil viscosity is increased compared with the initial oil viscosity. The interface zone 2 and zone 3 (gas/oil interface) is moving with time into the matrix block.
Zone 3: Increased drainage zone: oil viscosity is reduced by CO₂ diffusing into the oil; the gravity drainage rate is increased compared with the gravity drainage rate of the initial oil.

Zone 4: Methane depleted zone: due to the larger diffusion coefficient of methane than CO₂, this zone contains less methane than the initial oil. The CO₂ did not reach this area. Hence, the oil viscosity is slightly increased compared with the initial oil and the gravity drainage rate slightly decreased accordingly.

Zone 5: Oil at initial conditions: In this area, the oil is at initial conditions and gravity drainage at the “free fall gravity drainage rate” occurs (until gas breakthrough at the bottom of the matrix).

Figure 9-Different zones developing for injection of non-equilibrium gases.

In the following paragraphs, the effect of various parameters on the oil recovery is investigated.

Parameter variation

In this section, the impact of various modifications on the oil production is described. While all the other parameters were the same as described in the simulation model paragraph, one parameter as indicated below was changed.

Matrix permeability
The fracture permeability is not sensitive for the ultimate oil recovery in pervasively fractured reservoirs produced by gas/oil gravity drainage as long as the fracture permeability is large compared with the matrix permeability. The matrix permeability has a strong impact on the gas/oil gravity drainage rate and time of gas breakthrough at the bottom of the matrix. The characteristic drainage time of a block $T$ (assuming infinite gas mobility and no capillary pressure) is given by (Wit et al. 2002):

$$T = \frac{\phi H \mu_o}{\Delta \rho_{og} \phi g k_z}$$

(3)

With the porosity $\phi$, block height $H$ and oil viscosity $\mu_o$. The time $t_{BT}$ at which the gas front reaches the bottom of the block is given by

$$t_{BT} / T = 1/n$$

(4)

With the Corey oil relative permeability exponent $n$.

**Figure 10** shows that the gas breakthrough without diffusion is related to the reciprocal of the matrix permeability as expected from equation (3).

The larger the permeability, the smaller the difference in cumulative oil production with and without diffusion (**Figure 11**).

![Figure 10](image_url)

**Figure 10**-Different matrix permeabilities without diffusion versus the reciprocal gas breakthrough time.
In Figure 11, the difference in cumulative oil production (at diffusion gas breakthrough time) with time is plotted. While increasing the permeability leads to an increase in gas/oil gravity drainage rates and decreasing gas breakthrough time accordingly (see equation 3), the diffusion scales with the square root of time. Therefore, the difference in cumulative oil production with and without diffusion also scales with the square root of time. In other words, for lower matrix permeability, the longer the drainage times and hence the effect of diffusion is bigger.

Figure 12-Difference in cumulative oil production at gas breakthrough without diffusion for the different permeabilities versus square root of time.
Matrix porosity

Increasing the matrix porosity leads to a stronger effect of diffusion (Figure 13). In this case, the diffusion coefficients were the same as in the base case. Normalising the difference in cumulative oil production with and without diffusion shows that the diffusion effect scales about linear with the porosity (Figure 14). The higher the porosity, the more oil is affected at the same distance from the fracture by the diffusion of CO$_2$ into the matrix, since the oil volume per rock volume for high porosity is larger than smaller porosity. Therefore, the viscosity of more oil is decreased and drainage rate increased.

Figure 13-Difference in cumulative oil production with diffusion (DIFF) and without diffusion (NODIFF) at different times as a function of porosity.
Figure 14-Difference in cumulative oil production with and without diffusion as a function of the porosity multiplication for different times. The plot shows that the difference in cumulative oil production which is related to diffusion increases about linear with porosity.

Fracture spacing

The larger the fracture spacing, the smaller the difference of cumulative oil production with and without diffusion (Figure 15). Two effects are important to explain the behaviour: (1) for a larger fracture spacing, the oil production rate increases for a smaller fraction of the total block volume. Per unit volume of rock, more gas/oil interface area is available for diffusion and (2) at the vertical gas/oil interface, the oil is draining with a higher gas oil gravity drainage rate than in the unmodified oil zone below (Figure 16).

However, the incremental oil has to drain along the interface of the unmodified oil laterally towards the fracture. Therefore, the oil gravity drainage rate is reduced by sinus of the angle of the interface (sin $\theta$ in Figure 16). For larger fracture spacings, the angle $\theta$ and incremental gravity drainage rate is smaller.
Figure 15-Difference in cumulative oil production rate (logarithmic) with and without diffusion with fracture spacing.

Figure 16-Illustration of the gas/oil gravity drainage at the interface of the low viscosity zone and oil at initial conditions.

Matrix block height

The effect of the matrix block height on the difference in cumulative oil production with and without diffusion is shown in Figure 17. The larger the block height, the larger the difference in cumulative oil production. The reason is the larger interface of the fracture with the matrix block. Figure 17 is depicting normalised cumulative oil at three different times.
Figure 17-Normalised differences in cumulative oil production (cumulative oil production/cumulative oil production 50 m block height) versus block height for different times. The plot shows that the difference scales about linear with the block height. The larger the block, the more oil is affected by diffusion.

As shown in Figure 17, the rates are about linearly scaling with the block height. However, the relationship of cumulative oil production with block height is not strictly linear. In addition to the larger interface of the fracture, also other effects such as a smaller part of the total matrix block affected by the increased gravity drainage rate at the vertical interface play a role.

Injection of methane instead of CO2

Methane injection leads to a larger density difference compared with CO2 and oil. Therefore, the gravity drainage rate without diffusion is increased by the change in density difference. In the case discussed here, the density difference between CO2 and oil is 280 kg/m³ and of methane and oil 745 kg/m³. The gas/oil gravity drainage rate without diffusion is increased by the factor 2.6.

With diffusion, the oil production rate for CO2 injection is increased whereas for methane injection, only a small increase in cumulative oil production can be observed (Figure 18). The driving force for diffusion is the difference in concentration:

$$F = -D \frac{\partial c}{\partial x}$$

With the concentration gradient $\partial c/\partial x$. The oil contains only negligible amount of CO2. Therefore, the concentration difference is large for this injected gas. However, the oil is composed of 39 mol% of methane. Hence, the concentration gradient driving the diffusion flux is limited in the case of methane injection. The change in oil viscosity for both gases is very similar.
Effect of injection at different pressures

Lowering the pressure from 276 bar to 180 bar results in an increasing density difference of the oil and gas. In this case, the diffusion coefficients were the same as in the base case. Hence, the gas/oil gravity drainage rate is increased (Figure 19). With diffusion, the higher pressure leads to a larger increase compared to the same simulation without diffusion than the low pressure simulations (Figure 19). At low pressures, the partial pressure of CO₂ in the fracture and chemical potential as driving force for diffusion is reduced compared with the high pressure. Therefore, the difference between diffusion and no diffusion is larger for higher pressures than for lower pressures.
diffusion (NODIFF). Lower pressures result in higher gas/oil gravity drainage rates without diffusion. However, the difference between cumulative oil production with and without diffusion is reduced for the lower oil production rates.

Conclusions

Non-equilibrium gas injection into pervasively fractured reservoirs can result in improving oil production by gas/oil gravity drainage and diffusion of gas components from the gas filled fractures into the oil filled matrix.

In the case investigated here, the diffusion process is governed by the diffusion of gas components in the liquid. These components are increasing the gas/oil gravity drainage rate by reducing the oil viscosity. In addition, some stripping of components into the gas and production through in the gas phase occurs.

The process can be described by gas invasion into the top of the matrix block and creation of a zone of reduced viscosity at the gas/oil interface. This zone drains laterally along the interface to the fractures. In addition, gas diffuses through the fracture interface into the matrix and creates a vertical zone of reduced viscosity resulting in increased drainage rates. In parallel, conventional gas/oil gravity drainage is occurring in the unaltered oil zone.

While the diffusion of components scales with the square root of time, the gas/oil gravity drainage is governed by linear relations of the gas breakthrough at the bottom of the matrix with block height, density difference, permeability and porosity.

The difference in cumulative oil production simulated with and without diffusion scales linearly with porosity due to the larger affected oil volume for larger porosities with diffusion. With permeability, the difference in cumulative oil production with and without diffusion scales with the square root of time while it depends exponentially on fracture spacing.

For diffusion being significant, a large decrease in oil viscosity (due to gas components moving into the oil) compared with the initial oil viscosity, higher porosities, smaller fracture spacing, lower matrix permeability and larger block heights (longer drainage times and hence more time for diffusion) are required. In some cases, the difference in oil production is larger than 25 % if diffusion is not included into the simulation.

Dependent on the effectiveness of diffusion in relation to the gas/oil gravity drainage rates, gas injection at lower pressures might lead to higher or lower oil recovery rates than injection at higher pressures.
Acknowledgments
Many thanks to Ahmad Alavian and Curtis Whitson of Pera as well as Krijn Wit for the fruitful discussions and to OMV E&P for the permission to publish the paper.

Nomenclature

$A$ = cross sectional area, m²

$D$ = diffusion coefficient, m²/s

$F$ = diffusion flux, mol/m².s

$g$ = gravity constant, m/s²

$H$ = block height, m

$k_z$ = vertical matrix permeability, mD

$L$ = diffusivity length, m

$n$ = Corey exponent in rock relative permeability, (-)

$t$ = time, s

$t_{BT}$ = time of gas breakthrough at bottom of column, s

$T$ = drainage time of the block, s

$\Delta \rho_{og}$ = density difference between oil and gas, kg/m³

$\frac{\partial c}{\partial x}$ = concentration gradient

$\varphi$ = porosity, (-)

$\lambda_o$ = oil mobility, 1/cP

$\mu_o$ = oil viscosity, Pa.s

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