Effect of Compositional Grading on Reservoir Performance

M. Al-Rumhy, A. Al-Bemani and F. Boukadi

Department of Petroleum and Mining Engineering, Sultan Qaboos University, PO Box 33, Al Khod 123, Sultanate of Oman

ABSTRACT: In reservoirs with thickness exceeding fifty metres, compositional grading has been found to cause a significant variation in performance. Main fluid properties governing the magnitude of reservoir performance, such as density, formation volume factor and fluid viscosity, experience variation due to varying fluid composition along the hydrocarbon column. These variations cause erroneous estimation of stock-tank oil in place and may infer reservoir engineers to consider inappropriate secondary oil recovery methods, for example. In the presence of gravity segregation within the oil column, heavy ends will form a heavy oil blanket in the lower part of the reservoir. Such a scenario may result in poor displacement and an earlier breakthrough when water drive is the dominant fluid flow mechanism. In this paper, reservoir performance due to varying reservoir fluid composition, has been examined using reservoir simulation analysis and recommendations for better characterization of reservoir fluid sampling are outlined.

Many authors emphasised the possibility of compositional grading within a single oil pool and noted consequences of misleading estimation of pressure-volume-temperature (PVT) properties on reservoir performance and future field development.

Schulte (1980) noted considerable variation in composition and PVT properties with depth in various oil and gas-condensate fields. Hirschberg (1988) noted that significant compositional grading can occur in a reservoir because of gravity. He added that the effect can be inferred from reservoir fluid phase behaviour, noted that the heavy polar components play a key role in compositional grading of oil in reservoirs by gravity and he, in particular, remarked that in heavier oils (stock-tank oil gravity ≥ 0.85 g/cm³ [≤ 35° API]), asphaltene segregation will be the dominant effect. Riemens, Schulte and de Jong (1988) concluded that thermodynamic modelling of reservoir fluid indicated that gravity could have induced compositional variations along the hydrocarbon column. They added that field tests of a South Oman field, Bireba, confirmed the thermodynamic model to be correct. They also formulated a set of conditions causing a variation in reservoir fluid composition and properties in a single oil pool.

Schulte (1980) and Hirschberg (1988) and Mostel and Gouel (1985) also suggested the estimation of compositional grading, using the derived thermodynamic conditions for strong segregation, as soon as PVT data for reservoir fluids are available. The models proposed require fine tuning of equations of state (EOS) in order to match field acquired data. In tuning the equations of state, different proportions of C₇⁺ fractions have to be tested along with eccentric factors and binary interaction coefficients.

Lira-Galeana and Firoozabadi (1993) presented a thermodynamic framework to represent compositional changes due to gravity forces in hydrocarbon reservoirs. They described the compositional grading problem by continuous thermodynamics towards establishing the effect of gravity on C₇⁺ characterisation parameters.

Conditions Promoting Strong Segregation

Near critical conditions, light oils show a strong degree of gravity segregation, since any pressure drop
below saturation pressure will infer rapid changes in formation volume factor. For heavy oils, heavy ends accumulation at the base of the hydrocarbon column is enhanced with presence of large molecules whose density is significantly different from the average reservoir fluid density. Thermal, compositional and mechanical forces are in the origin of fluid change in composition with depth. Treating composition of the oil in a given layer as an open system that can interchange matter with its underlain layer, then the total Gibbs free energy, \( nG \), which is a function of temperature and pressure, is also a function of the number of moles of the various chemical species present in the layer. This can be expressed as follows:

\[
nG = f(T, P, n_1, n_2, \ldots, n_j) \quad (1)
\]

where, \( n_j \) represents the mole numbers of the chemical species; \( T \), the temperature; and \( P \) the pressure.

Hence the total differential form of \( G \) may be presented as:

\[
dG = \left( \frac{\partial G}{\partial T} \right)_P dT + \left( \frac{\partial G}{\partial P} \right)_T dP + \sum \left( \frac{\partial G}{\partial x_j} \right)_{T,P} dx_j
\]

(2)

As detailed in the appendix, assuming temperature change within the interval is negligible, equation 2 leads to the following expression that relates mole fraction of component \( j \), \( x_j \), as a function of depth, \( h \):

\[
dG = \left( \frac{\partial G}{\partial P} \right)_T \rho g dh + \sum \mu_j dx_j
\]

(3)

where \( \mu_j \) is the chemical potential.

Simulation Model Description

A single-well model was built to simulate production performance of a layered system with each layer having characteristic PVT properties. The PVT properties of the condensate reservoir vary with depth in such a manner that heavy liquid components have increasing proportions in the bottom layers. Gravity segregation was taken to be in the origin of the accumulation of heavy ends in higher proportions at the base of the hydrocarbon column. At bubble-point pressure, the formation volume factor ranges between 3.52 to 1.91 bbl/stb, viscosity increases from 0.070 to 0.151 cp and solution gas-oil ratio decreases from 4.44 to 1.72 Mscf/stb with an increasing depth of 545 feet. No natural water drive is anticipated in the field and the ultimate recovery from the field depends largely on the gas-oil ratio segregation rate in the reservoir.

Eclipse 100 black-oil simulator was used to investigate the effects of treating the reservoir as a single PVT region. The black-oil model was also used in simulating the behavior of a layered system portraying different PVT regions. Each layer was then considered as a PVT region resulting from grading. PVT properties for each layer were generated using Eclipse PVT package grading option. Sensitivities were run to show the effects of unrepresentative sampling of reservoir fluids on estimation of stock-tank oil in place and thereafter layer/reservoir production performances.

<table>
<thead>
<tr>
<th>Properties</th>
<th>Top Layer</th>
<th>Layer 2</th>
<th>Layer 3</th>
<th>Layer 4</th>
<th>Bottom Layer</th>
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<tr>
<td>( C_1 )</td>
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<td>77.761</td>
<td>76.765</td>
<td>75.855</td>
<td>75.010</td>
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<tr>
<td>( C_2 )</td>
<td>15.364</td>
<td>16.492</td>
<td>17.496</td>
<td>18.415</td>
<td>19.270</td>
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<tr>
<td>( N_2 )</td>
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<td>0.746</td>
<td>0.732</td>
<td>0.721</td>
<td>0.710</td>
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<tr>
<td>( CO_2 )</td>
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<td>3.821</td>
<td>3.830</td>
<td>3.836</td>
<td>3.840</td>
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<td>( H_2S )</td>
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<td>1.180</td>
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<td>1.172</td>
<td>1.170</td>
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<td>38.9</td>
<td>34.8</td>
<td>31.4</td>
<td>28.4</td>
</tr>
<tr>
<td>( B_{ob} )</td>
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<td>3.397</td>
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<tr>
<td>( \mu_{ob} )</td>
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<td>2.880</td>
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<td>0.0849</td>
<td>0.1023</td>
<td>0.124</td>
<td>0.151</td>
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</table>

API American Petroleum Institute gravity
\( B_{ob} \) Formation volume factor at bubble-point pressure, bbl/stb
\( R_{ob} \) Solution gas-oil ratio at bubble-point pressure, Mscf/stb
\( \mu_{ob} \) Viscosity at bubble-point pressure, cp

<table>
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<th>Properties</th>
<th>Dimension</th>
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<tr>
<td>( \Delta x )</td>
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<td>( \Delta z )</td>
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Figure 1. Overall Field Performance.
Figure 2. Overall Layer 1 Performance
Sensitivity studies indicated that for a given reservoir, single-point (depth) reservoir fluid sampling can be in the origin of misrepresentation of layer/region fluid distribution, layer/region production contribution and can lead to the choice of inappropriate lost reservoir energy replacement forms and even wrong solutions to wellbore problems.

**Sensitivity Studies**

Sensitivity analysis was performed for a hypothetical reservoir having five layers. Each layer is represented by a different set of PVT properties. The reservoir fluid studied is richer in Methane at shallower depths, while the mole fractions of heavier components are found in lower proportions. Consequently, the bubble-point pressure of the fluid decreases with increasing depth and a jump in viscosity values of the oil is noted low in the structure. The distribution of composition within the pay zone is in accordance with a proposal by Riemans, Schulte and de Jong (1988). Using such distribution, composition changes gradually with depth and the fluid becomes heavier and richer in aromatics down dip. Six different cases were examined to show the effect of unrepresentative reservoir fluid sampling and the subsequent uncharacteristic reservoir performance predictions. Five cases in which the reservoir is represented by a single PVT zone are studied. Each fluid sample caught in the middle of each layer is taken as a representative reservoir fluid sample. In the sixth case examined, the reservoir fluid composition varies with depth and five PVT zones represented fluid distribution in the reservoir. Fluid compositions and PVT properties pertaining to different PVT zones are shown in table 1.

**Discussion of the Results**

Figures 1 through 4 represent the results of simulation runs on different scenarios, as far as the changes in PVT properties variations with depth are concerned. Four cases were considered. On three cases, reservoir performance was determined based on a given layer PVT properties. As a comparison, a “control” run, where reservoir performance was based on all five “layers” PVT data, was simulated. The other two cases which touch upon the reservoir performance of layers 2 and 4 were not discussed since they describe an “in-between” behaviour. Layer 2 reservoir performance is “in-between” the performance of the top layer, layer 1, and the middle layer, layer 3. Layer 4 reservoir performance is “in-between” the performance of the middle layer, layer 3, and the bottom layer, layer 5. Other than the hydrocarbon fluids properties, all reservoir data was kept the same for all layers, as shown in table 2.

**Comparison of field performance simulated under single and multiple PVT data**

As shown in figure 1, treating the reservoir oil as a light oil column, by sampling in the top section and assigning PVT properties of the top layer to all reservoir layers, will lead to overestimation of field gas production, underestimation of oil production and prediction of early field water production. A thin oil column with high proportions of gas was simulated causing high amounts of solution gas production and enhancing water fingering due to severe gravity unbalance and an unfavourable mobility ratio. As indicated in figure 1a, contribution of the different layers toward oil production is dictated by proportions of the liquid phase accumulation. Liquid phase distribution in different PVT layers increases with depth due to gravity segregation. For that reason, early on in the life of the field, liquid production is predominantly coming from the bottom layers 5, 4 and 3, with layer 5 contributing the most, then layer 4 and layer 3 in lower proportions. Layer 4 liquid contribution is higher than that of layer 3. Liquid production from the top layers, 1 and 2, is minimal as the top layers produce gas at higher proportions (figure 1b). Simulation results will not reflect real field behaviour. That will cause a misinterpretation of the results and a possible history matching dilemma. Furthermore, as a result of the inappropriate reservoir fluid sampling, additional costs will be incurred due to inappropriate sizing of surface facilities and planning of early wellbore and reservoir remedial actions such as waterflooding and/or gas injection for pressure maintenance purposes. On the other hand, sampling the bottom section of the reservoir will result in underestimation of field gas production, overestimation of oil production and prediction of late field water production (figure 1c). This will lead to serious consequences due to inappropriate sizing of surface facilities and late pressure maintenance overtaking which will result in a loss of significant recoverable hydrocarbons.

Furthermore, each layer performance with respect to oil/gas/water production is investigated individually. Production performance of each layer in a multiple PVT is compared to the performance of that layer when that layer PVT is assumed to represent the reservoir PVT.

**Case 1 : Performance based on top layer PVT data**

Results of this run are shown in figure 2. These results are based on the hypothesis that sampling of reservoir fluid was made on the top layer of the reservoir. With such assumption, lighter components of the hydrocarbon will be the dominant, as detailed in table 1. As such, higher gas production was observed (figure 2b). Overall field production (refer to figure 1), in
Figure 3. Overall Layer 3 Performance.
Figure 4. Overall Layer 5 Performance.
comparison to the "control" run, shows a gross under
correction to the "control" run, shows a gross under
estimated production. This is due to the fact that the top
layer hydrocarbon accumulation is predominantly in a
gaseous phase which will not contribute toward liquid
phase production (figure 2a). Other performance criteria,
such as gas and water production, also confirmed the
effect of compositional grading. Profile of water
production, if top layer's sample is considered to
represent reservoir behaviour, shows a much earlier
breakthrough (figure 2c). Gravity unbalance between a
very light fluid column overlying a denser phase, bottom
water, has enhanced water fingering and initiated water
production.

Case 2 : Performance based on middle layer PVT
data.

Interesting results were obtained from the middle
layer. Comparing the top, middle and bottom layers with
the "control" run, the mid-layer PVT data produced the
most accurate result. In terms of reservoir thickness, this
layer lies exactly at the centre of the pay zone.
Performance results are shown as figure 3. The results
from this layer are in agreement with Shultz's (1980)
work. He explained that the gradient \( \frac{dx_j}{dh} \) of the mole
fraction \( x_j \) of component \( j \) is related to the chemical
potential by the following relationship:

\[
\sum_j \left( \frac{\partial \mu_j}{\partial x_j} \right) \frac{dx_j}{dh} = \left( \rho - m_j \right) g = \left( \rho - \rho_j \right) g
\]

where:

- \( \rho \) = average reservoir fluid density
- \( V_j \) = partial molar volume of component \( j \)
- \( m_j \) = molar mass of component \( j \)
- \( \rho_j \) = density of component \( j \)
- \( g \) = acceleration due to gravity.

Strong segregation of component \( j \) can be expected if
\( \left( \rho - V_j \right) m_j \) is large or if \( \left( \rho - \rho_j \right) \) is large. This implies
that it is also true for molecules with density \( \rho_j \)
significantly different from the average reservoir fluid
density, \( \rho \). In this case, where layer 3 represents the
mid-layer in our case study, the mid-layer fluid density,
\( \rho_j \) used is 53,094 lb/cuft compared to the average
reservoir fluid density, \( \bar{\rho} \), (control sample) of 52,937
lb/cuft. Because the difference in densities is minimal, no
significant segregation will take place at the mid-layer.

Case 3 : Performance based on bottom layer PVT
data.

The bottom layer represents the other side of the
scale in terms of the hydrocarbon properties. PVT data
from this layer are dominated by relatively heavier
components than the top layers. This fact is reflected in
the field performance (see figure 4). In oil production
(figure 4a), results show a much exaggerated profile, in
gas production profile, (figure 4b), it is underestimated
and water production, (figure 4c), is much favourable
when compared with the "control" run. Figure 4 shows
the magnitude of the effects of using sample from layer
5. Production rates of both oil and gas are over-
estimated. Water production, on the other hand, is
underestimated. This is due to the fact that the oil phase
gravity is heavier than anticipated. For that reason, a
better gravity balance has eliminated the possibility of
water phase fingering and retarded water production.
The high oil phase density in the bottom layer has
allowed a sharper bottom water displacement front
dictated by a more favourable mobility ratio between the
displacing bottom-water phase and displaced oil phase.

Conclusions

The simulation study presented in this paper has
highlighted the magnitude of errors in estimating
reservoir performance.

An increase in the amount of heavier pseudo-
component with depth indicated a pronounced
compositional segregation in the reservoir studied. Then,
careful reservoir fluid sampling has to be undertaken for
better reservoir fluid PVT properties characterisation.
But, since fluid sampling at different depths is a time
consuming and a highly expensive practice, it was found
that sampling in the middle of the oil column will lead to
acceptable PVT properties representation yielding
trustful history matching results.

In this paper, it was shown that by sampling deeper
in the hydrocarbon fluid column, an overestimation of oil
production coupled with an underestimation of water
production, due to a more favourable displacement
process, and an underestimation of gas production, due
to miscalculation of the amount of gas in solution, will
lead to unrealistically optimistic view of the field
performance. Gravity unbalance and unrepresentative
gas production figures are the two major overlooked
problems which will be in the origin of mismatching field
and simulation results. On the other hand, sampling in
shallow depths will lead to an exaggerated indication of
solution gas proportions along the whole oil column.
Misinterpretation of the results may lead to the
conclusion of defining the reservoir as a predominantly
gas reservoir. In this paper, gravity segregation theory
proved that finding an oil ring accumulation underlying
the light gaseous phase is a possibility with increasing probability of occurrence in reservoirs having a pay thickness exceeding 50 m.

Sampling depth of a heavy oil as well as near-critical conditions light oil is a key issue since consequences of an inappropriate sampling depth choice can be the origin of misleading reservoir/layer performance results. Therefore, along with appropriate mid-column sampling depth, compositional segregation checks can be done on sampled reservoir fluid using available thermodynamic models for an accurate representation of reservoir fluid PVT properties.

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Appendix

The total Gibbs free energy of a layer (an open system) which can interchange matter (i.e. heavy molecules) with underlying layers is defined as:

\[ nG = f(T, P, n_1, n_2, \ldots, n_j, \ldots) \]  \hspace{1cm} (A1)

where, \( n_j \) represents the mole numbers of the chemical species. Division by \( n \), the total number of moles in a given layer, yields the following alternative equation:

\[ G = f(T, P, x_1, x_2, \ldots, x_j, \ldots) \]  \hspace{1cm} (A2)

where, \( x_j = n_j / n \) is the mole fraction of component \( j \).

Hence the total differential form of \( G \) may be presented as:

\[ dG = \left( \frac{\partial G}{\partial T} \right)_P dT + \left( \frac{\partial G}{\partial P} \right)_T dP + \sum \left( \frac{\partial G}{\partial x_j} \right)_{T,P} dx_j \]  \hspace{1cm} (A3)

but since temperature change within a single layer is minimal, i.e. \( dT = 0 \), then equation (3) reduces to:

\[ dG = \left( \frac{\partial G}{\partial P} \right)_T dP + \sum \left( \frac{\partial G}{\partial x_j} \right)_{T,P} dx_j \]  \hspace{1cm} (A4)

Also by setting chemical potential \( \mu_j \) as:

\[ \mu_j = \left( \frac{\partial G}{\partial x_j} \right)_{T,P} \]  \hspace{1cm} (A5)

equation (4) can be transformed to the following form:

\[ dG = \left( \frac{\partial G}{\partial P} \right)_T dP + \sum \mu_j dx_j \]  \hspace{1cm} (A6)

Since pressure, \( P_j \), at the base of the oil column with a height, \( h_j \), in a given layer is expressed as:

\[ P_j = \rho g h_j \]  \hspace{1cm} (A7)

where \( \rho \) is the average layer fluid density, then

\[ dP_j = \rho g dh_j \]  \hspace{1cm} (A8)

and substitution of equation (8) into equation (6) yields:

\[ dG = \left( \frac{\partial G}{\partial P} \right)_T \rho g dh_j + \sum \mu_j dx_j \]  \hspace{1cm} (A9)

References


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