PREDICTING WHEN CONDENSATE BANKING BECOMES VISIBLE ON BUILD-UP DERIVATIVES

By

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

September 2010
Declaration of Own Work

I declare that this thesis

‘Predicting when Condensate Banking becomes visible on Build-up Derivatives’

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.

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Abstract

Condensate banking (accumulation) near the wellbore, as a result of production below the dew point pressure, reduces gas productivity, liquid recovery and poses additional challenges in well test analysis. Past studies on gas condensate fields show that condensate banking creates a fluid-induced composite behaviour in well test analysis when analysed with the normalised single-phase pseudo-pressure function developed by Al-Hussainy et al. (1966). The effect of condensate banking is visible on drawdown derivatives as soon as the flowing bottomhole pressure (FBHP) drops below the dew point, but is delayed on build-up (BU) derivatives (Krukrubo and Gringarten 2009). This study focuses on developing methods for predicting the time (onset) when condensate banking becomes visible on BU derivatives in medium-rich and rich gas condensate reservoirs, using compositional simulation and well test analysis.

Krukrubo and Gringarten (2009) identified mobility contrast as the key parameter that controls the onset of condensate banking on BU derivatives in lean gas reservoirs, for a given relative permeability curve. This study aims at verifying that the same applies to medium-rich and rich fluids and also at determining the appropriate ranges of mobility contrast. The sensitivities investigated in this study are the relative permeability end-points (gas and condensate), critical condensate saturation and gas production rate prior to shut-in.

Simulation results confirm that mobility contrast at onset time is approximately constant in both medium-rich and rich gas reservoirs, for any given relative permeability curve. Sensitivity analyses indicate that mobility contrast at onset time is fluid dependent, higher in rich gas than in medium-rich gas, for the same relative permeability curves and gas production rate, and ranges approximately from 2.2 to 2.7 for medium-rich gas and from 2.8 to 3.7 for rich gas. Finally, this study concludes that the relationship between gas production rate and onset time is best represented by a power law equation.
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Nomenclature and Abbreviations

\(\frac{(kh/\mu)}{1/2}\) Mobility ratio between region 1 and 2
\(P_{av}\) Initial average reservoir pressure (psia)
\(\mu_g\) Gas viscosity (cp)
\(\mu_o\) Condensate (oil) viscosity (cp)
1D One dimensional
2D Two dimensional
bbl Barrels
BU Build-up
\(C_a\) Prediction equation coefficient for Fluid-A
\(C_b\) Prediction equation coefficient for Fluid-B
CGR Condensate gas ratio
\(C_o\) Liquid content of gas per unit volume
cp Centipoise (viscosity unit)
Eq. Equation
FBHP Flowing bottomhole pressure (psia)
Fig. Figure
\(h\) Reservoir thickness (ft)
k Permeability (mD)
k_1 Permeability of inner region (mD)
k_2 Permeability of outer region (mD)
k_{abs} Absolute reservoir permeability (mD)
k_g Effective permeability to gas phase (mD)
k_{rg} Gas phase relative permeability (mD)
k_{rg}^{max} Gas end-point relative permeability
\(k_{ro}\) Oil phase relative permeability
\(k_{rog}^{max}\) Condensate relative permeability in gas
\(k_{rog}\) Condensate relative permeability
\(M_c\) Mobility contrast (dimensionless)
mD Milli-darcy
\(M_{init}\) Initial total mobility (mD/cp)
MMscf/D Million standard cubic feet per day
\(M_{onset}\) Total mobility at onset time (mD/cp)
\(M_t\) Total mobility (mD/cp)
n Exponent of rate vs onset time relationship
\(n_a\) Prediction equation exponent for Fluid-A
\(n_b\) Prediction equation exponent for Fluid-B
\(nm(p)\) Normalized single-phase pseudo-pressure (psi)
\(\varnothing\) Porosity (fraction)
p Pressure (psi)
\(Q\) Gas production rate (MMscf/D)
r Wellbore radius (ft)
r_1 Radius of inner composite region (ft)
S Skin factor
\(S(w)\) Near-wellbore skin factor
\(S_g\) Gas saturation
\(S_o\) Condensate (oil) saturation
\(S_{oc}\) Critical condensate saturation
STB Stock Tank Barrel
\( S_{wc} \) Connate water saturation
\( T_{onset} \) Onset time (days)
\( \text{WTA} \) Well test analysis
\( \text{Z} \) Fluid component
\( \lambda_g \) Gas Corey exponent
\( \lambda_o \) Oil Corey exponent

**Nomenclature in Appendix**

\( S_{row} \) Residual oil saturation in water (fraction)
\( S_w \) Water saturation (fraction)
\( k_{rw} \) Relative permeability to water
\( k_{row} \) Relative permeability to oil in water
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Abstract
Condensate banking (accumulation) near the wellbore, as a result of production below the dew point pressure, reduces gas productivity, liquid recovery and poses additional challenges in well test analysis. Past studies on gas condensate fields show that condensate banking creates a fluid-induced composite behaviour in well test analysis when analysed with the normalised single-phase pseudo-pressure function developed by Al-Hussainy et al. (1966). The effect of condensate banking is visible on drawdown derivatives as soon as the flowing bottomhole pressure (FBHP) drops below the dew point, but is delayed on build-up (BU) derivatives (Krukrubo and Gringarten 2009). This study focuses on developing methods for predicting the time (onset) when condensate banking becomes visible on BU derivatives in medium-rich and rich gas condensate reservoirs, using compositional simulation and well test analysis.

Krukrubo and Gringarten (2009) identified mobility contrast as the key parameter that controls the onset of condensate banking on BU derivatives in lean gas reservoirs, for a given relative permeability curve. This study aims at verifying that the same applies to medium-rich and rich fluids and also at determining the appropriate ranges of mobility contrasts. The sensitivities investigated in this study are the relative permeability end-points (gas and condensate), critical condensate saturation and gas production rate prior to shut-in.

Simulation results confirm that mobility contrasts at onset time are approximately constant in both medium-rich and rich gas reservoirs, for any given relative permeability curve. Sensitivity analyses indicate that mobility contrasts at onset time are fluid dependent, higher in rich gas than in medium-rich gas, for the same relative permeability curves and gas production rate, and range approximately from 2.2 to 2.7 for medium-rich gas and from 2.8 to 3.7 for rich gas. Finally, this study concludes that the relationship between gas production rate and onset time is best represented by a power law equation.

Introduction
Understanding the near-wellbore dynamics of gas condensate reservoirs producing below the dew point pressure is crucial for optimum hydrocarbon recovery. The cost and risk of developing reservoirs below the dew point pressure highlights the need to be able to predict the recovery of gas and liquids (Barnum et al. 1995). Several factors such as initial productivity, amount of near-wellbore liquid saturation due to condensation, and relative permeability appear to affect the observed level of productivity decline (Barnum et al. 1995).

Some past studies show that different regions exist in a gas condensate reservoir producing below its dew point pressure. Kniazeff et al. (1965) identified two additional regions to the condensate bank namely: the region where the condensate is immobile and the region farther away from the wellbore with the original gas in place. However, there is an increase in the relative permeability of gas in the immediate vicinity of the wellbore (velocity stripping), which compensates for the condensate banking effects. This causes an improvement in gas mobility near the wellbore (Gondouin et al. 1967). This improvement in gas mobility near the wellbore also referred to as ‘positive coupling’ (Boon et al. 1995; Henderson et al. 2000) occurs at high capillary numbers. The capillary number (dimensionless) is a ratio between viscous force and capillary force. However, the ‘velocity stripping’ region is not seen in rich gas condensate reservoirs (Kgogo and Gringarten 2010).

Gringarten et al. (2000) has shown that ‘velocity stripping’ creates a fourth zone in the immediate vicinity of the wellbore. According to Gringarten et al. (2000), these mobility regions appear as a 3-region radial composite behaviour in well test analysis (Fig. 1). Bozorgzadeh and Gringarten (2004) published a method for estimating the storativity ratios between different regions from BU data. This method was then used for calculating the condensate bank radius.

Krukrubo and Gringarten (2009) published a methodology for predicting when the effect of condensate banking becomes visible on BU derivatives of lean gas reservoirs. According to Krukrubo and Gringarten (2009), the mobility contrast in lean gas reservoirs must reach a critical value ranging from 1.7 to 2.1 before condensate banking becomes visible on BU derivatives. This study extends the same prediction methodology to medium-rich and rich gas condensate...
reservoirs, and determines the range of mobility contrasts through sensitivity studies on the relative permeability end-points, critical condensate saturation, and gas production rate.

Methodology
This study adopted the workflow (Fig. 2) and methodology used by Krukrubo and Gringarten (2009).

Fluid characterization
Two fluid models were used, namely: Fluid-A (Aluko and Gringarten 2009) and Fluid-B (Kgogo and Gringarten 2010). Fluid-A is a rich gas condensate with an initial condensate-gas ratio (CGR) of 237 STB/MMscf. Fluid-B is a medium-rich gas condensate with an initial CGR of 110 bbl/MMscf. Both fluids PVT were modelled using the Peng–Robinson equation of state (PR EOS). The heavy components of the fluids were lumped into pseudo-components to improve computational efficiency. Table 1 shows the final fluid compositions used for the PVT modelling. The two fluid models gave reasonable matches with laboratory experiments (Figs. B-3 through B-6 of Appendix B). The complete compositions of the two fluids are shown in Tables B-1 and B-2 of Appendix B, respectively. The phase diagrams are also shown in Appendix B.
Relative permeability modelling

The relative permeability curves used in this study were generated using the Corey’s correlation described by Eq.1 and 2 (Liu et al. 2001). The Corey parameters were adjusted until a reasonable match (Fig. 3) was achieved with actual data from a rich gas condensate reservoir (Aluko and Gringarten, 2009). An immobile water phase is assumed.

\[ k_{rg} = k_{rg}^{\text{max}} \left( \frac{S_g - S_{gr}}{1 - S_{gr} - S_{wc}} \right)^{n_{rg}} \]  
(1)

\[ k_{rog} = k_{rog}^{\text{max}} \left( \frac{1 - S_g - S_{gr} - S_{wc}}{1 - S_{wc} - S_{oc}} \right)^{n_{rog}} \]  
(2)

Details of relative permeability models and the match values for the Corey parameters are shown in Appendix C.

**Relative permeability sensitivity study:** The shapes and end-points of the relative permeability curves, as well as the critical condensate saturation, greatly control the degree of productivity reduction below the dew point (Barnum et al. 1995). This work investigated the impact of the relative permeability curves by studying the effects of gas end-point relative permeability \( k_{rg}^{\text{max}} \), condensate end-point relative permeability \( k_{rog}^{\text{max}} \) and critical condensate saturation \( S_{oc} \) for both fluids.

**Simulation model set-up**

The simulation model was set up as a 1D radial grid with Fluid-A and Fluid-B for the rich and medium-rich study, respectively. The single layer 1D radial grid consists of 120 cells in the radial direction with a vertical thickness of 50 ft (Fig. 4). The inner radius of the model is 0.354 ft (corresponds to the radius of the wellbore). The grid cell size increases logarithmically away from the wellbore to ensure that near-wellbore effects are well represented. The outer radius of the model is about 50000 ft to ensure that there are no boundary effects in the pressure transient response. Porosity and permeability were 13% and 100mD, respectively.

**Model validation**

**Validation with homogenous properties:** Validation involves the use of uniform values of porosity and permeability throughout the entire grid. A 60-days single drawdown and 60-days BU sequence was simulated with initial reservoir pressure above the dew point and gas rate of 5MMscf/D (to ensures single-phase flow during drawdown), and compared with the corresponding analytical solution (Fig. 5 and Table 2). Details of model validation are given in Appendix D.
**Parameter Model Input Well Test Output Difference**

- \((P_{\text{av}})_i\), psia 5500 5502 +0.04%
- \(k_1\) (inner zone), mD 5.00 4.89 -2.2%
- \(k_2\) (outer zone), mD 20.00 19.25 -3.8%
- \((k_h/\mu)^{1/2}\) 0.25 0.254 +0.4%
- \(r_1\), ft 37 41 +9.8%
- \(S(w)\) 0 -0.38 -0.38

---

**Validation with heterogeneities:** This validation incorporates anisotropy in the permeability of the model. Permeability value of 5mD was assigned to each of the first 40 grid cells (inner region) and 20mD assigned to the remaining 80 grid cells (outer region, in order to verify the radial composite behaviour of the simulation model. The simulation was run with a gas rate of 3MMscf/D and duration of 60 days each (drawdown and BU). **Fig. 6** and **Table 3** show the comparison with the corresponding analytical solution.

**Compositional simulation runs**

Setting the initial reservoir pressure close to the dew point ensures that the FBHP drops below the dew point shortly after the start of production. Simulation uses equal durations for drawdown and BU’s. This study adopted a logarithmic time scale to optimize the number of reported data points within every log cycle. The methodology of the sensitivity study involves iteration on time (drawdown and BU duration) until the condensate banking becomes visible on the BU derivative (See **Fig. 2**).

**Near-Wellbore Fluid Dynamics**

This section discusses some fluid dynamics in the near-wellbore region resulting from production below the dew point pressure. The fluid properties are evaluated in the grid cell closest to the wellbore (grid cell 1). Fluid properties in other grid cells are also calculated to determine the profiles in the radial direction.
Effect of condensate banking on total mobility

This study defines the total mobility of the reservoir ($M_t$) in terms of gas and oil phase only (Eq. 3).

$$M_t = k_{abs} \left( \frac{k_{rg} + k_{ro}}{\mu_g + \mu_o} \right)$$

(3)

Simulation results show that the initial total mobility in the near-wellbore region (single-phase gas) remains almost constant during early production until liquid drop-out occurs. The liquid hydrocarbon (condensate) accumulates with time thereby decreasing the gas mobility in the near-wellbore region. This reduces the total fluid mobility even though the oil phase mobility is increasing. Fig. 7 illustrates how condensate banking affects the total mobility.

Gas mobility profile in the radial direction

Gas mobility reduces with time once the FBHP falls below the dew point pressure. This results from increasing condensate saturation, which reduces the effective permeability to gas in the near-wellbore region. Fig. 8 illustrates how the mobility profile of the gas phase changes in the radial direction at different drawdown (DD) durations. The region of reduced gas mobility (which has a large impact on productivity) increases radially as drawdown duration increases.

Effect of drawdown duration on condensate banking

The condensate saturation increases with drawdown duration as a result of continuous liquid dropout (caused by prolonged production below the dew point pressure). As the drawdown period increases, pressure drops below the dew point pressure further in the reservoir and the radial extent of condensate accumulation (bank radius) increases (Fig. 9).

![Fig. 7: Effect of condensate banking on total mobility in grid cell 1](image1)

![Fig. 8: Gas mobility profile in the radial direction at different drawdown duration](image2)

![Fig. 9: Condensate saturation profile in the radial direction at different drawdown duration](image3)

![Fig. 10: Condensate saturation profile at different gas production rates](image4)
Effect of gas production rate on condensate banking

According to Muskat (1949), the rate of condensate banking (accumulation) is proportional to the square of gas production rate

\[
\frac{dS_o}{dt} = \frac{\mu_s Q_g}{(2\pi h)^{1/2} \phi} \frac{dC_o}{dp} \tag{4}
\]

This is illustrated in Fig. 10 illustrates how the rate of condensate banking increases with gas production rate.

Mobility regions

Previous studies indicate that different mobility regions exist in gas condensate reservoirs as a result of condensate drop-out. The first region is in the immediate vicinity of the wellbore where the ‘velocity stripping’ occurs. The second region close to the wellbore has gas and mobile condensate saturations. The third region farther away from the wellbore has gas and immobile condensate saturations, and the last region farthest away from the well has single-phase gas saturation (original gas in place). The ‘velocity stripping’ region is not seen in rich gas condensate reservoirs (Kgogo and Gringarten 2010).

Fig. 11 shows that the last three regions described above are visible in the case of the medium-rich Fluid-B. The region of increased gas mobility (velocity stripping) near the wellbore is not seen because the permeability of the simulation model used in this study is high. However, the ‘velocity stripping’ region is seen in low-permeability medium-rich gas condensate reservoirs (Kgogo and Gringarten 2010). For the rich gas Fluid-A, the region of immobile condensate saturation is almost invisible for all cases studied. This observation can be attributed to the high initial condensate yield of the fluid because high condensate saturation increases the tendency of the condensate phase to become mobile as the critical saturation is reached faster (Fig. 12).

Drawdown and Build-up Derivatives

The effect of condensate banking is visible on drawdown derivatives as soon as the FBHP drops below the dew point pressure but is delayed in the case of BU’s (Figs. 13 and 14). Fig. 13 shows the simulated pressure profile for Fluid-B producing at 15MMscf/D for 5 days followed by a 5 days shut-in. The FBHP dropped below the dew point pressure (4200 psia) at about 0.03 days. The drawdown derivative plot starts to rise at approximately 0.03 days (Fig. 14) as a result of continuous decline in gas mobility (proportional to gas effective permeability). This is not the same for the BU derivative even though the FBHP is far below the dew point at the beginning of BU. Krukrubo and Gringarten (2009) noted that the mobility at the end of drawdown is not the same as that at the start of BU. Hence the delay in BU derivative can be attributed to the change in mobility (Krukrubo and Gringarten 2009). The effect of condensate banking becomes visible on the BU derivative when the ratio of the total mobility in the near-wellbore region to the gas mobility in the reservoir above the dew point pressure reaches a critical value.
Krukrubo and Gringarten (2009) investigated the parameters that determine the onset of condensate banking in BU derivatives in lean gas condensates. They concluded that the condensate phase exceeding its critical value is not a criterion for the bank to be visible on BU derivatives. The same observation exists for the medium-rich and rich fluids. The next section will discuss the parameters investigated in this study.

**Parameters that control the onset of Condensate Banking on BU derivatives**

The onset of condensate banking on BU derivatives is highly influenced by production rates and rock/fluid properties. These include the richness of the fluid, absolute reservoir permeability, and the shapes of relative permeability curves (rock physics). Fig. 15 shows the definition of onset time.

As stated earlier, the effect of condensate banking becomes visible only when the ratio of the total mobility \( (M_{\text{onset}}) \) in the near-wellbore region to the gas mobility \( (M_{\text{initial}}) \) above the dew point pressure, reaches a critical value (Fig. 16). This ratio is also referred to as ‘mobility contrast \( (M_c) \)’ (Eq. 5). To ascertain the applicable range of mobility contrast for the medium-rich and rich gas, sensitivity analyses were conducted on the relative permeability end-points (gas and oil), critical condensate saturation, and gas production rates.

\[
M_c = \frac{M_{\text{initial}}}{M_{\text{onset}}}
\]

(5)
Gas end-point relative permeability ($k_{rg}^{max}$)

The condensate end-point was fixed at 1 while the gas end-point was given successive values of 1, 0.8, and 0.6.

**Effect of $k_{rg}^{max}$ on onset of condensate banking:** Simulation results for both fluids show that reducing the effective permeability to gas (through $k_{rg}^{max}$) hastens the onset of condensate banking on BU derivatives for the same gas rate (Tables 4 and 5). Fig. 17 and 18 show that condensate accumulation is relatively higher for a lower value of $k_{rg}^{max}$, at any given gas rate. This is as a result of the decrease in the effective permeability ($k_{g}$) to gas which is inversely related to the rate of condensate accumulation (Eq.4), according to Muskat (1949). Increase in the rate of condensate bank accumulation results in earlier onset of condensate banking on BU derivatives. This observation is the same for both fluids studied.

The mobility contrast is approximately constant for the same value of $k_{rg}^{max}$ (Figs. 19 and 20) and did not change much for the three cases studied in each fluid. Sensitivity results show that mobility contrast at onset time decreases with $k_{rg}^{max}$ for a given gas rate. This is as a result of reduction in the initial mobility of gas phase (through $k_{rg}^{max}$). Details of $k_{rg}^{max}$ sensitivity results are given in Appendix E.

![Fig. 17: Condensate accumulation for different $k_{rg}^{max}$ (Fluid-A @ 15 MMscf/D, and 1 day drawdown)](image1)

![Fig. 18: Condensate accumulation for different $k_{rg}^{max}$ (Fluid-B @ 13.5 MMscf/D, and 5 days drawdown)](image2)

![Fig. 19: Mobility contrast (Fluid-A)](image3)

![Fig. 20: Mobility contrast (Fluid-B)](image4)

**Table 4: Results of $k_{rg}^{max}$ sensitivity (Fluid-A)**

<table>
<thead>
<tr>
<th>$k_{rg}^{max}$ (fraction)</th>
<th>$Q$ (MMscf/d)</th>
<th>$T_{onset}$ (days)</th>
<th>$M_{initial}$ (mD/cp)</th>
<th>$M_{onset}$ (mD/cp)</th>
<th>$M_c$</th>
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**Table 5: Results of $k_{rg}^{max}$ sensitivity (Fluid-B)**

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<th>$k_{rg}^{max}$ (fraction)</th>
<th>$Q$ (MMscf/d)</th>
<th>$T_{onset}$ (days)</th>
<th>$M_{initial}$ (mD/cp)</th>
<th>$M_{onset}$ (mD/cp)</th>
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**Gas rate vs. onset time relationship:** It is obvious from the results (Tables 4 and 5) that increasing the gas rate hastens the onset of condensate bank (for a given relative permeability curve). The gas rates were plotted against corresponding onset times in order to better describe the relationship, for each relative permeability case. The trends were best fitted in all cases with power law equations of the general form described by Eq. 6. Figs. 21 and 22 show the gas rate vs. onset time relationships for Fluid-A and Fluid-B respectively.

\[ Q = C (T_{onset})^{-n} \]  

(6)

\( Q \) is in MMscf/D and \( T_{onset} \) in days.

\[ \begin{align*}
C_a &= -25.2 \left( k_{rg}^{max} \right)^2 + 61.97 \left( k_{rg}^{max} \right) - 12.29 \\
n_a &= -0.1125 \left( k_{rg}^{max} \right)^2 + 0.1725 \left( k_{rg}^{max} \right) + 0.036 \\
C_b &= 35 \left( k_{rg}^{max} \right)^2 - 35.865 \left( k_{rg}^{max} \right) + 23.51 \\
n_b &= -0.0875 \left( k_{rg}^{max} \right)^2 + 0.3625 \left( k_{rg}^{max} \right) - 0.135
\end{align*} \]  

(7)  

(8)

**Onset time prediction based on \( k_{rg}^{max} \) sensitivity:** The onset time was predicted for both fluids using different values of \( k_{rg}^{max} \) and gas rates.

- **Fluid-A:** The onset time was predicted with \( k_{rg}^{max} = 0.7 \) and \( Q = 16\text{MMscf/D} \). Using the correlations given by Eq. 7, the prediction equation becomes:

\[ Q = 18.74 (T_{onset})^{-0.102} \]  

(9)

Solving Eq. 9 for \( Q = 16\text{MMscf/D} \) gives the onset time, \( T_{onset} \approx 5 \) days. Analysis of simulated pressure data verifies the prediction with relative permeability curve of \( k_{rg}^{max} = 0.7 \), gas rate of 16 MMscf/D, and duration of 5 days (same for both drawdown and BU). Fig. 23 shows the BU of the simulated pressure data verifying that condensate banking is visible on the BU derivative.

- **Fluid-B:** The onset time was predicted with \( k_{rg}^{max} = 0.85 \) and gas rate of 14MMscf/D. Using the correlations given in Eq. 8, the prediction equation becomes:

\[ Q = 18.31 (T_{onset})^{-0.11} \]  

(10)
Solving Eq. 10 for \( Q = 14 \text{MMscf}/\text{D} \) gives the onset time, \( T_{\text{onset}} \approx 11.5 \text{ days} \). This was verified with simulation and BU analysis of the simulated pressure data. Fig. 24 verifies condensate banking is seen on the BU derivative after 11.5 days drawdown.

Condensate end-point relative permeability (\( k_{\text{rog}}^{\text{max}} \))

This sensitivity study was achieved by fixing the gas end-point at 0.8 while the condensate end-point was varied as 1, 0.8, and 0.7 successively.

**Effect of \( k_{\text{rog}}^{\text{max}} \) on the onset of condensate banking**: Results show that lowering \( k_{\text{rog}}^{\text{max}} \) causes relative delays in the onset of condensate bank on BU derivatives, for any given gas rate (Tables 6 and 7). This delay can be attributed to lower oil phase mobility at any given saturation (reverse of the effect of gas end-point). At any given gas rate, the restriction to gas flow due to condensate banking is less pronounced at lower \( k_{\text{rog}}^{\text{max}} \); hence the condensate banking delays on the BU derivative. Results indicate that the delay in onset time is greater in Fluid-A (rich gas) than Fluid-B (medium-rich gas) at any given gas rate. However, the delay is not seen in the case of lean gas condensate reservoirs (Krukrubo and Gringarten 2009).

Similarly as in the case of gas end-point, the mobility contrast (\( M_c \)) in both fluids is also approximately constant for a given \( k_{\text{rog}}^{\text{max}} \) (Figs. 25 and 26) even though the gas rates are different. Details of \( k_{\text{rog}}^{\text{max}} \) sensitivity results are shown in Appendix F.
**Gas rate vs. onset time:** Power law equations of the general form described previously in Eq. 6 best described the relationship between gas rates and corresponding onset times. Figs. 27 and 28 show the power law trends for Fluid-A and Fluid-B respectively. Eq. 11 and 12 respectively give the correlations of \( k_{\text{rog}}^{\text{max}} \) with ‘C’ and ‘n’.

### Table 6: Results of \( k_{\text{rog}}^{\text{max}} \) sensitivity (Fluid-A)

<table>
<thead>
<tr>
<th>( k_{\text{rog}}^{\text{max}} ) (fraction)</th>
<th>( Q ) (MMscf/d)</th>
<th>( T_{\text{onset}} ) (days)</th>
<th>( M_{\text{initial}} ) (mD/cp)</th>
<th>( M_{\text{onset}} ) (mD/cp)</th>
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### Table 7: Results of \( k_{\text{rog}}^{\text{max}} \) sensitivity (Fluid-B)

<table>
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<th>( T_{\text{onset}} ) (days)</th>
<th>( M_{\text{initial}} ) (mD/cp)</th>
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**Onset time prediction based on \( k_{\text{rog}}^{\text{max}} \) sensitivity:** The onset time was predicted for both fluids using different values of \( k_{\text{rog}}^{\text{max}} \) and gas rates.

**Fluid-A:** The onset time was predicted with \( k_{\text{rog}}^{\text{max}} = 0.6 \) and gas rate of 19MMscf/D. Using the correlations described by Eq. 11, the relationship between gas rate and onset time becomes:

\[
C_a = 58.683 \left( k_{\text{rog}}^{\text{max}} \right)^2 - 96.605 \left( k_{\text{rog}}^{\text{max}} \right) + 59.08
\]

\[
n_a = 0.9167 \left( k_{\text{rog}}^{\text{max}} \right)^2 - 1.465 \left( k_{\text{rog}}^{\text{max}} \right) + 0.6503
\]

**Fluid-B:** The onset time was predicted with \( k_{\text{rog}}^{\text{max}} = 0.6 \) and gas rate of 16MMscf/D. Using the correlations described by Eq. 12, the relationship between the gas rate and onset time becomes:

\[
C_b = -12.183 \left( k_{\text{rog}}^{\text{max}} \right)^2 + 11.475 \left( k_{\text{rog}}^{\text{max}} \right) + 17.926
\]

\[
n_b = -0.55 \left( k_{\text{rog}}^{\text{max}} \right)^2 + 0.865 \left( k_{\text{rog}}^{\text{max}} \right) - 0.216
\]

Solving Eq. 13 for \( Q = 19\text{MMscf/D} \) gives the onset time, \( T_{\text{onset}} \approx 5 \text{ days} \). The simulation was re-run with \( k_{\text{rog}}^{\text{max}} = 0.6, \) gas rate of 19 MMscf/D and time steps corresponding to 5 days drawdown followed by 5 days BU. Fig. 29 shows the BU analysis of the simulated pressure data verifying that condensate banking is visible on BU derivative after 5 days drawdown.

**Fluid-B:** The onset time was predicted with \( k_{\text{rog}}^{\text{max}} = 0.6 \) and gas rate of 16MMscf/D. Using the correlations described by Eq. 12, the relationship between the gas rate and onset time becomes:
\[ Q = 20.43(T_{\text{onset}})^{-0.105} \] (14)

Solving Eq. 14 for \( Q = 16\text{MMscf/D} \) gives the onset time, \( T_{\text{onset}} \approx 10 \text{ days} \). The simulation was re-run with \( k_{rog}^{\text{max}} = 0.6 \), gas rate of 16 MMscf/D and time step of 10 days drawdown followed by 10 days BU. Fig. 30 shows the BU analysis of the simulated pressure data verifying that condensate banking is visible on BU derivative after 10 days drawdown.

Critical condensate saturation \( (S_{oc}) \)

This sensitivity study was done with \( k_{rog}^{\text{max}} \) and \( k_{rg}^{\text{max}} \) fixed at 0.8 and 1 respectively. \( S_{oc} \) values of 0.1 (base case), 0.08 (equivalent to 20% decrease), and 0.15 (equivalent to 50%) are used successively.

Effect of \( S_{oc} \) on onset time: The critical condensate saturation controls how quick the condensate phase becomes mobile. The condensate phase (bank) is less prone to flow at a higher \( S_{oc} \). Higher critical saturation indicates higher condensate bank stability (more resistance to flow) and consequently results to an earlier onset time, for the same gas rate (see results in Tables 8 and 9). Lower \( S_{oc} \) indicates that the condensate phase is more prone to flow. Hence for a given gas rate and drawdown duration, the tendency of liquid (condensate) to accumulate will be less in the case of lower \( S_{oc} \) which causes a relative delay in the onset of condensate bank on the BU derivative.

Simulation results show that \( M_c \) is approximately constant for a given \( S_{oc} \) (Figs. 31 and 32). Details of \( S_{oc} \) sensitivity results are shown in Appendix G.
Gas rate vs. onset time: As shown in previous sensitivity studies, the gas rate-onset time relationship is best represented by power law equations (Figs. 33 and 34). Eq. 15 and 16 give the correlations of $S_{oc}$ with 'C' and 'n' for Fluid-A and Fluid-B respectively.

| Table 8: Results of $S_{oc}$ sensitivity (Fluid-A) |
|-------------------|-------------------|-------------------|-------------------|
| $S_{oc}$ (fraction) | $Q$ (MMscf/d) | $T_{onset}$ (days) | $M_{initial}$ (mD/cp) | $M_{onset}$ (mD/cp) | $M_c$ |
| 0.15 | 13.5 | 10 | 1381 | 379 | 3.6 |
| 15 | 8 | 1382 | 378 | 3.7 |
| 17.5 | 1 | 1384 | 379 | 3.7 |
| 0.1 | 15 | 30 | 1382 | 436 | 3.2 |
| 17.5 | 6 | 1389 | 432 | 3.2 |
| 25 | 0.2 | 1389 | 434 | 3.2 |
| 0.08 | 15 | 45 | 1382 | 459 | 3.0 |
| 17.5 | 7 | 1384 | 456 | 3.0 |
| 20 | 1 | 1386 | 456 | 3.0 |

Onset time prediction based on $S_{oc}$ sensitivity: The onset time was also predicted for the two fluids using different values of $S_{oc}$ and gas rates.

Fluid-A: The onset time was predicted with $S_{oc} = 0.12$ and gas rate of 14MMscf/D. Using the correlations given by Eq.15, the relationship between gas rate and onset time becomes:

$$Q = 20.79 (T_{onset})^{-0.107}$$

(17)

Eq. 17 gives the onset time, $T_{onset}$ ~ 40 days for $Q = 14$ MMscf/D. Analysis of the simulated pressure data verifies the prediction with $S_{oc} = 0.12$, gas rate of 14 MMscf/D, and 40 days duration (drawdown and BU). Fig. 35 confirms that condensate banking is visible on BU derivative after 40 days drawdown.

Fluid-B: The onset time was predicted for $S_{oc} = 0.12$ and gas rate of 11MMscf/D. Using the correlations given by Eq. 16, the prediction equation becomes:

$$Q = 16.63 (T_{onset})^{-0.122}$$

(18)
Eq. 18 gives the onset time, \( T_{\text{onset}} \sim 30 \) days for \( Q = 11\text{MMscf/D} \). Analysis of the simulated pressure data also verified the prediction with \( S_{\text{oc}} = 0.12 \), gas rate of 11MMscf/D, and 30 days duration. Fig. 36 shows the BU analysis of the simulated pressure data confirming that condensate banking is visible after 30 days drawdown.

Conclusions
This study led to the following conclusions:

1. The time at which condensate banking first appear on build up derivatives (onset time) is controlled by the ratio of the total mobility in the near-wellbore region to the gas mobility above the dew point pressure. The mobility ratio is approximately constant for a given relative permeability curve,
2. The mobility ratio at onset time is fluid dependent. It is higher for a rich fluid than for the medium-rich fluid, and lower for a lean fluid. It ranges from 2.8 to 3.7, approximately, for the rich gas used in this study, and from 2.2 to 2.8 for the medium-rich gas. The range is from 1.7 to 2.1 for lean gas (Krukrubo and Gringarten 2009).
3. Onset time is related to gas rate by power law equations for all the relative permeability cases and fluid types investigated. These equations can be used to predict when the condensate bank might be seen on the build-up derivative for different rates of production and for different reservoir parameters.

Recommendations for Further Studies
This study extensively investigated only 3 parameters: gas end-point relative permeability, condensate end-point relative permeability, and critical condensate saturation. Preliminary sensitivity study conducted on the gas Corey exponent \( \lambda_g \) indicates that for the same gas rate, a lower \( \lambda_g \) delays the onset of condensate banking on the BU derivative. This is because the miscibility of the two phases increases with lower \( \lambda_g \). Also, preliminary study shows that the oil Corey exponent \( \lambda_o \) has little or no impact on the onset time. Furthermore, observation shows that reducing the absolute reservoir permeability \( k_{\text{abs}} \) hastens the onset of condensate banking on BU derivatives for the same gas rate and relative permeability curve. In addition, it was observed that the ‘velocity stripping’ zone becomes visible in the medium-rich fluid at very low \( k_{\text{abs}} \) and/or high gas rates. These are observations from preliminary studies and need to be verified extensively with the methodology presented by this study.

Nomenclature and Abbreviations

- \( (kh/\mu)^{1/2} \): Mobility ratio between region 1 and 2
- \( (P_{\text{av}})_{h} \): Initial average reservoir pressure (psia)
- \( \mu_g \): Gas viscosity (cp)
- \( \mu_o \): Condensate (oil) viscosity (cp)
- \( 1D \): One dimensional
- \( 2D \): Two dimensional
- \( bbl \): Barrels
- \( BU \): Build-up
- \( C_a \): Prediction equation coefficient for Fluid-A
- \( C_b \): Prediction equation coefficient for Fluid-B
- \( CGR \): Condensate gas ratio
- \( C_o \): Liquid content of gas per unit volume
Predicting when Condensate Banking becomes visible on Build-up Derivatives

References


APPENDICES

Nomenclature in Appendix

\( k_{row} \) Relative permeability to oil in water
\( k_{rw} \) Relative permeability to water
\( S_{row} \) Residual oil saturation in water (fraction)
\( S_{W} \) Water saturation (fraction)
APPENDIX A - Critical Literature Review

Table A-1: Milestone in Gas Condensate Study

<table>
<thead>
<tr>
<th>Source</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPE 962</td>
<td>1965</td>
<td>Two-Phase Flow of Volatile Hydrocarbons</td>
<td>Kniazeff, V. J., and Naville, S. A.</td>
<td>First to develop non-linear numerical solutions to partial differential equation for radial two-phase flow. This became the basis for present reservoir simulators. First to relate the loss of gas deliverability to condensate accumulation.</td>
</tr>
<tr>
<td>SPE 1478</td>
<td>1967</td>
<td>An Attempt To Predict The Time Dependence of Well Deliverability in Gas Condensate Fields.</td>
<td>Gondouin, M., Iffly, R., and Husson, J.</td>
<td>Extension of the work of Kniazeff and Naville with the introduction of flow equations with boundaries. The developed model was applied to Hassi Er R'Mel gas condensate field.</td>
</tr>
<tr>
<td>Journal of Petroleum Technology</td>
<td>1973</td>
<td>Single-Well Performance Predictions for Gas Condensate Reservoirs</td>
<td>Fussel D.D</td>
<td>First to attribute the loss of productivity in gas condensate reservoirs to condensate accumulation below the dew point pressure.</td>
</tr>
<tr>
<td>SPE 30767</td>
<td>1995</td>
<td>Gas Condensate Reservoir Behaviour: Productivity and Recovery Reduction due to Condensation</td>
<td>R.S. Barnum, F.P Brinkman, T.W. Richardson, and A.G. Spillette,</td>
<td>First to show that productivity impairment results in gas recovery reduction for wells with a permeability-thickness below 1000 mD-ft.</td>
</tr>
<tr>
<td>SPE 1243</td>
<td>1996</td>
<td>The flow of Real Gases through Porous Media</td>
<td>Al-Hussainy R, Ramey, H.J., Jr., and Crawford, J.</td>
<td>First to introduce the single-phase gas pseudo-pressure function (real gas potential)</td>
</tr>
<tr>
<td>SPE 62920</td>
<td>2000</td>
<td>Well Test Analysis in Gas Condensate Reservoirs</td>
<td>Gringarten A. C., Daungkaw S., Mott R., and Whittle T. M.</td>
<td>First to show the existence of 3-region radial composite behaviour in well test analysis of gas condensate reservoirs</td>
</tr>
<tr>
<td>SPE 62933</td>
<td>2000</td>
<td>The Relative Significance of Positive Coupling and Inertial Effects on Gas Permeabilities at High Velocity</td>
<td>Henderson, G. D., Danesh, A., Tehrani, D. H., and Al-Kharusi, T.</td>
<td>First to report that gas-condensate relative permeability will increase with increasing velocity</td>
</tr>
<tr>
<td>SPE 68178</td>
<td>2001</td>
<td>Modelling a Rich Gas-Condensate Reservoir with Composition Grading and Faults</td>
<td>Liu, J.S., Wilkins, J. R., Al-Qahtani, M. Y., and Al-Awami A. A.</td>
<td>First to show the relationship between Corey gas exponent and critical condensate saturation</td>
</tr>
<tr>
<td>SPE 89904</td>
<td>2004</td>
<td>Condensate-Bank Characterization From Well-Test Data and Fluid PVT Properties</td>
<td>Bozorgzadeh M., and Gringarten A.C.</td>
<td>Introduced a new method of estimating the storativity ratios between different zones from build-up data, which is then used to calculate the condensate-bank radius.</td>
</tr>
<tr>
<td>SPE 121326</td>
<td>2009</td>
<td>Predicting the Onset of Condensate Accumulation near the Wellbore in a Gas Condensate Reservoir</td>
<td>Krukrubo G. J., and Gringarten A.C.</td>
<td>First to develop a method for predicting when the effect of condensate accumulation can be seen on the build-up derivative response of a lean gas condensate reservoir.</td>
</tr>
<tr>
<td>SPE 121848</td>
<td>2009</td>
<td>Well Test Dynamics of Rich Gas Condensate Reservoirs under Gas Injection</td>
<td>Aluko O. A., and Gringarten A.C.</td>
<td>First to show the impact of condensate bank re-vaporization as a result of re-pressureisation by gas injection.</td>
</tr>
<tr>
<td>SPE 134452</td>
<td>2010</td>
<td>Comparative Well-Test Behaviours in Low-Permeability Lean, Medium-rich, and Rich Gas-Condensate Reservoirs</td>
<td>Kgogo T. C., and Gringarten A. C.</td>
<td>First to give a detailed comparison of well test behaviour in different types of low-permeability gas condensate reservoirs.</td>
</tr>
</tbody>
</table>
1. SPE 962 (1965)

Title: Two-Phase Flow of Volatile Hydrocarbons.

Authors: Kniazeff, V. J. and Naville, S. A.

Contribution to understanding of Gas Condensate Reservoirs
The authors were first to develop numerical solutions to non-linear partial differential equations for two-phase radial flow. The numerical solutions developed in this paper became the basis for present reservoir simulators.

Objective(s) of the paper
- To numerically solve the non-linear partial differential equation for radial two phase flow around the well taking into account the thermo dynamical properties of the fluid and physical properties of the reservoir.
- To better understand the drainage mechanism of a two-phase flow of volatile hydrocarbons and gas condensate reservoir.

Methodology used:
- A zone in the porous reservoir where the flow properties and the in situ composition of the fluids can be assumed to be uniform was considered.
- Developed a computer program to numerically solve the partial differential equations of pressure and saturation as a function of the radial distance around the well and time.
- Numerical solution is used with the aid of computer programming (FORTRAN) to solve the two-phase flow problem. Basic equation is the equations of mass continuity. Darcy's Law is used to have an expression of rock flow properties using the effective permeability of each phase instead of absolute permeability. An empirical formula (Fetkovich's formula) that has a quadratic relationship between the velocity and the pressure gradient is then used to evaluate the productivity of the well.
- Evolution of bottomhole pressures, well productivities and effluent compositions with the depletion of the reservoir is derived and the results were applied to the Sabarian gas condensate field.
- Gas condensates were treated as a binary mixture through an arbitrary division of the chemical components into two groups. The light components consisting of sales gas and the heavier components consist of the Gasoline at the separator.
- The fluid properties are expressed using partial specific masses of the two main separator products. Saturation and Pressure profiles with time are calculated numerically by computer.
- A large digital computer is used to numerically solve the problem of transient two-phase flow for volatile oil and gas condensate reservoirs.

Conclusions reached
- A zone of fairly high liquid saturation develops around the well reducing the effective permeability and represents a loss of condensable products in addition to retrograde condensation. In this zone deviation from Darcy law for gas phase flow governs the well deliverability.
- The cost of computation using the defined program in place of existing ones is reduced even with high speed and powerful electronic computers.
- It was shown (by solving partial differential equations) that condensate saturation builds up once the bottomhole pressure drops below the dew point and this in turn reduces the gas deliverability.

Comments
Numerical solutions developed in this paper for radial system became the basis for present reservoir simulators. This paper gave a better understanding of condensate reservoir behaviour.
2. SPE 1478 (1967)

Title: An Attempt to Predict the Time Dependence of Well Deliverability in Gas Condensate Fields.

Author: Gondouin, M., Iffly, and R., Husson, J.

Contribution to understanding of Gas Condensate Reservoirs
This paper is an extension of Kniazeff and Naville’s work with the introduction of flows equations with boundaries.

Objective(s) of the paper
- To investigate the behaviour of gas condensate wells producing at high rates and the factors affecting the well’s deliverability.

Methodology used:
- Numerical simulations are used with different boundary conditions. The model emphasizes the effect of non-Darcy flow around the well bore with high rates.
- Extended the work of Kniazeff, V.J. and Naville, S.A. (1962) and developed flow equations with boundary (assuming thermodynamic equilibrium between the two co-existing phases in the pore scale) and solved the equations numerically.
- The numerical model developed for gas and condensate flow takes into account secondary gasoline deposited in the pore space as a result of pressure reduction, and non-Darcy flow of gas in the vicinity of the wells.
- Applied the developed model to Hassi Er R'Mel gas condensate field.

Conclusions reached
Although a good quantitative agreement was obtained, the inherent inaccuracies in the field measurements of flow rates and pressure make it difficult to achieve perfect matching of computed and field results. In addition, the assumption of a homogeneous reservoir of uniform thickness and transmissivity is probably unwarranted over so large a drainage area (nearly 40,000 acres).

Finally, it must be recognized that the production history used for the calculations is a gross simplification of the actual well flow rate history, a fact which may also lead to minor discrepancies. Nevertheless, the results obtained show that the computer programs presented here can be used confidently to predict future well performance in gas condensate fields. In that case, the limitations introduced by the various simplifying assumptions used in the programs become relatively unimportant in comparison with a correct description and a quantitative evaluation of the main features of the flow phenomena. These include: (1) the radial extension of a zone of high liquid saturation around the well, (2) the non-Darcy flow of gas into the well and (3) the simultaneous flow of liquid phase with the gas phase. These factors all contribute to the changes in well performance, and must be taken into account when predicting future well deliverability.

The numerical programs presented here and the experimental techniques developed to obtain the required core data constitute a practical set of tools for evaluating the technical and economic aspects of the exploitation of gas condensate fields. Their use in the huge Hassi Er R'Mel field illustrates some of their possible applications.

Comments
This paper attributes the zone of increased mobility to non-Darcy effects.
3. JPT: Vol 25, No 7 Pages 860 -870 (1973)

Title: Single-Well Performance Predictions for Gas Condensate Reservoirs.

Author: Fussell D.D.

Contribution to understanding of Gas Condensate Reservoirs
This study described the effect of condensate accumulation on well productivity in relation to fluid composition.

Objective(s) of the paper
- To evaluate the effect of phase equilibrium and relative permeability on well performance.
- To show the effect of condensate accumulation on well productivity.

Methodology used:
- Adopted a modified version of 1-D radial compositional model developed by Roebuck et al (1960) for the study.
- Neglected gravity and capillary pressure effects.
- Compared the predicted kh products to ascertain the accuracy of the finite difference model.

Conclusions reached
- The magnitude of the condensate saturation is significantly affected by the relative permeability characteristics of the formation.
- Productivity index of a well can be reduced by up to a factor of 3 as a result of condensate banking.
- Shutting in the well during build up does not alleviate the condensate bank.
- The radial model presented is accurate and stable over simple steady-state model.
- The productivity of a well is drastically reduced in the case of condensate accumulation in the immediate vicinity of the wellbore.
- The radial model gives a much better performance forecast than the steady-state method.

Comments
Gas condensate characteristics were described in this paper as a function of fluid composition and relative permeability only.

Title: Gas Condensate Reservoir Behaviour: Productivity and Recovery reduction due to Condensation

Authors: R.S. Barnum, F.P. Brinkman, T.W. Richardson and A.G. Spillette.

Contribution to knowledge of Gas Condensate Reservoirs
Showed that productivity impairment results in gas recovery reduction for wells with a permeability-thickness below 1000 mD-ft.

Objectives of the paper
- To evaluate the historical frequency and severity of productivity impairment due to near-wellbore condensate build-up.
- To identify reservoir parameters associated with severe productivity and recovery reduction.

Methodology used
- Used finely gridded radial (R-Z) models of limited areal extent.
- Volatile oil model was used in preference to more complex compositional simulation.
- A fully-coupled, semi-implicit reservoir simulator was used to simulate the performance during pressure depletion.
- Two case studies were carried out each on clastic and carbonate reservoirs respectively.

Conclusions reached
- Condensation of hydrocarbon liquids in gas condensate reservoirs can severely restrict gas productivity.
- The range of critical condensate saturation seen in the literature, 10 to 50%, is supported by the history match of the two examples.
- Simulation suggests the potential for significant losses in gas recovery for initial permeability-thickness below 1000 mD-ft over a range of condensate yields.
- Field data suggest that gas recoveries below 50% are limited to reservoirs below 1000 mD-ft.

Comments
This study did not consider interfacial tension and involved the measurement of end point gas relative permeability.
5. SPE 1243 (1966)

Title: The Flow of Real Gases through Porous Media

Arthurs: R. Al-Hussainy, H. J. Ramey Jr., and P. B. Crawford

Contribution to knowledge of Gas Condensate Reservoirs
The authors developed the real gas potential (single-phase pseudopressure function) which makes the gas diffusivity equation linear.

Objectives of the paper
- To describe fundamental considerations which can be used successfully to analyze the flow of real gases.

Methodology used
- A rigorous gas flow equation was developed which is a second order, non-linear partial differential equation with variable coefficients. This equation was reduced by a change of variable to a form similar to the diffusivity equation, but with potential dependent diffusivity.
- Superposition of the linearized real gas flow solutions to generate variable rate performance was investigated and found satisfactory.
- Application of the real gas pseudo-pressure to radial flow systems under transient, steady-state or approximate pseudo-steady-state injection or production was considered.
- Superposition of the linearized real gas flow solutions to generate variable rate performance.

Conclusions reached
- Pseudo-pressure technique can be used to analyse real gas flow. This concept gives a considerable simplification and improvement in all phases of gas well testing analysis and gas reservoir calculations.
- The transformation called real gas pseudo-pressure in this paper reduces a rigorous partial differential equation for the flow of the real gas in an ideal system to form similar to the diffusivity equation, but with potential dependent diffusivity.
- The variation of the diffusivity of real gas with pressure was similar to that of an ideal gas; it was possible to correlate finite difference solution for the ideal radial production of real gas from a bounded system with the liquid flow solutions and the ideal gas solution.
- It avoids the assumption of small pressure gradients in the reservoir and offers generally useful solutions for the radial flow of real gas.
- A rigorous gas flow equation was developed which is a second order, non-linear partial differential equation with variation coefficients.

Comments
The pseudo-pressure function developed in this paper is used in pressure transient analysis of gas reservoirs.

Title: Well Test Analysis in Gas Condensate Reservoirs

Author(s): Gringarten A. C., Al-Lamki A., Daungkaew S., Mott R. and Whittle T. M.

Contribution to understanding of Gas condensate Reservoirs
Demonstrated the existence of a third mobility region (zone) in the immediate vicinity of the wellbore with high capillary number which compensates the loss in gas productivity due to condensate banking.

Objective(s) of the paper:
- To investigate the existence of three mobility zones in gas condensate reservoirs which occur as a result of condensate drop out and velocity stripping near the wellbore.
- To establish a better understanding of near wellbore effects in Gas-Condensate reservoirs using well testing and use it to develop methods for predicting well productivity.

Methodology used:
- Simulated radial homogenous compositional reservoir model with and without capillary number effects to generate pressure transient tests. The build up data were then analysed using well testing software.
- Adopted a model which consists of 40 cells with an outer radius of 11950 ft to remove any boundary effects in the simulated well tests. The cell size increases logarithmically away from the wellbore.
- The initial pressure is set just above the dew point pressure in all simulation cases, so that the condensate forms at the start of production.
- The first drawdown is extended (100 days) to allow enough time for the condensate to accumulate near-well bore region, and the subsequent periods are ten day long.
- The simulator determines the fluid PVT properties using an eqn.-of-state and varies the condensate and gas relative permeability as a function of the capillary number, \( N_c \), according to methods developed by Henderson et al 1995 and 1997.

Conclusions reached:
- The paper presented the preliminary results of a schematic study of well tests in gas condensate reservoirs.
- Phase redistribution was a major problem in analysis of data.
- The existence of three mobility zones was verified by three stabilizations on the derivative.
- The results of the paper have to be considered with caution until more systematic evidence of such behaviour becomes available.

Comments
The results of this paper presented a baseline for understanding the three mobility regions present in a gas condensate reservoir. More studies have to be carried out on the research area to establish the fact.
Title: The Relative Significance of Positive Coupling and Inertial Effects on Gas Condensate Relative Permeabilities at High Velocity.

Author(s): G. D. Henderson, A. Danesh, D. H. Tehrani and B. Al-Kharusi

Contribution to understanding of Gas condensate Reservoirs

The authors were the first to report that gas-condensate relative permeability will increase with increasing velocity.

Objective(s) of the paper:
- To develop empirical correlations, which relate the change of gas-condensate relative permeability to variations in fluid saturation, velocity and IFT.
- To investigate the flow of gas condensate fluids in the wellbore region of gas condensate reservoirs, and in particular to investigate the effect that inertia would have on the relative permeability.

Methodology used:
- A high pressure core facility was developed to allow steady-state relative permeability tests to be conducted to a high degree of accuracy.
- Within the core facility, constant volumes of gas and condensate were stored in separate high pressure vessels and were circulated in a closed loop around the flow system, which increased the accuracy of fluid saturation measurements.
- The pumps used to circulate the gas phase have a range in flow rate from 1 to 24000 cc/hour, with the fluid volumes displaced into the core being measured with a resolution of 0.01cc.
- The condensate phase was circulated through the core using pumps with a maximum velocity which was in the region of 2000 cc/hour.
- Fluid production from the core was measured at the test conditions in a high pressure sight glass situated at the core outlet to within an accuracy of ±0.1 cc.
- The differential pressure was measured using two high accuracy Quartz dyne quartz crystal transducers located at the inlet and outlet of the core, which provided stable differential pressure data to an accuracy of ±0.0007 MPa, during the course of the tests.
- The values obtained from the differential pressure transducer, and subsequently used in the calculation of relative permeability, resulted in a maximum error which ranged from ±0.5% at low flow rates, to ±0.05% at the highest flow rates.
- Each core sample tested was initially saturated with methane which was then injected through the core, with the gas flow rate being increased in increments from 100 to 10,000 cc/hour (on average a pore velocity of 7 to 700 m/day) to measure the gas permeability reduction associated with inertial flow.
- Prior to measuring the gas condensate relative permeability at each test conditions, the core was saturated with 100% single phase equilibrium gas at the required test pressure. The equilibrated gas was obtained by depleting the gas condensate fluid in the storage cells to the selected test pressure below the dew point.
- The individual phases were then mixed to equilibrate the fluids by flowing them together through the fluid bypass line at the test pressure, followed by separating the gas and condensate phases into their own storage cells.
- Each equilibrated phase was kept at a pressure above its saturation point to ensure lack of phase change. The equilibrium gas phase was then injected through the core to displace the methane, at a pressure well above the saturation pressure. When fully saturated with equilibrium gas, the core pressure was reduced to a pressure just above the saturation pressure.
- Equilibrium gas was then injected into the core and the flow rate was increased in increments from 100 to 10,000 cc/hour, to measure the gas permeability reduction associated with inertial flow. This data was used as the gas permeability endpoints at a condensate saturation of zero on the subsequently measured relative permeability curves.
• The pressure in the core was then raised, and single phase gas condensate fluid, approximately 3.447 MPa above the dew point, was injected into the equilibrium gas saturated core. Two HCPV of gas condensate were injected and left for 24 hours, after which further gas condensate was injected until the differential pressure across the core was stable.

• At the start of each test sequence, the gas and condensate saturations in the core were known from PVT data. The initial volumes of gas and condensate in the flow system, (fluid storage cells, flow lines, and sight glass), were measured prior to the test commencing, to within an accuracy +0.5 cc. After steady-state conditions were established, the core was isolated from the flow system, and any change in the condensate saturation in the core was calculated from the change in the total volume of condensate in the flow system between the beginning and the end of each test.

Conclusions reached:

• The effect of positive coupling was evident at high velocity and at high IFT for three different cores, with the gas relative permeability in particular increasing with increasing velocity at near wellbore flow rates.

• "Cross over" relative permeability curves have been reported, which show a transition from inertia dominated relative permeability curves with increasing velocity at low condensate saturations corresponding to low CGR's, to conditions where the positive coupling effect was dominant as the condensate saturation and CGR increase.

• The positive coupling effect continued to increase the relative permeability up to the highest tested velocity of almost 700 m/day at the highest tested IFT of 0.78 mNm-1. A set of generalised relative permeability correlations accounting for both inertia and positive coupling effects have been developed.
8. **SPE 68178 (2001)**

**Title:** Modelling a Rich Gas-Condensate Reservoir with Composition Grading and Faults

**Author(s):** Liu, J. S., Wilkins, J. R., Al-Qahtani, M. Y., and Al-Awami, A. A.

**Contribution to understanding of Gas Condensate Reservoirs**

These authors were first to show the relationship between Corey gas exponent and critical condensate saturation.

**Objective(s) of the paper:**

To model a reservoir with complex structural-stratigraphic traps (Hawiyah Jauf Reservoir).

**Methodology used:**

- Construction of geological model (single-well and full-field): Sixty-six faults were interpreted from 3D seismic coverage shot over the southwest part of the entire model area.
- Fluid characterization.
- Relative permeability modelling.
- Field performance forecast.

**Conclusions reached:**

- The LGR is required at well locations in order to duplicate the fine-grid well performance of a gas condensate reservoir in a full-field model. The LGR should be at well blocks in a full-field model so that a realistic forecast of field performance can be obtained.
- The unstructured gridding (e.g. PEBI grid) offers the advantage of modelling well more accurately and a significant saving in CPU time.
- Laboratory experiments must be carried out to identify all important aspects that will affect the reservoir performance and to obtain the necessary data using the appropriate core and reservoir fluid.
- Each identified aspect should be studied using a representative single well model. After the specific effect has been quantified, the effect should be introduced into the full-field model by the most economic way.

**Comments**

The result of this study is specific to Hawiyah Jauf Reservoir but the methodology can be applied to other complex stratigraphic reservoir models.

Title: Condensate-Bank Characterization from Well-Test Data and Fluid PVT Properties

Author(s): Manijeh Bozorgzadeh and Alain C. Gringarten

Contribution to understanding of Gas Condensate Reservoirs

Introduced a new method of estimating the storativity ratios between different zones from build-up data which is then used to calculate the condensate-bank radius

Objective(s) of the paper:

To present a new method based on the determination of the saturation profile during build-ups, to estimate the storativity ratios between the different zones from well test and PVT data so that the radii can be calculated.

Methodology used:

- Used compositional simulation with capillary number and inertia effects under different production conditions to determine the various condensate saturation profiles that may exist in the near wellbore region at the end of shut-in
- The initial reservoir pressure was set just above the dew point pressure in all cases.
- Irreducible water was assumed to be immobile.
- Capillary number and non-Darcy effects were obtained from correlations developed by Henderson et al (1998, 2000a and 2000b) and Geertsma 1974.
- A finely gridded 1D radial, fully compositional model was used with no wellbore storage, mechanical skin effect, or flow within the producing string.

Conclusions reached:

- The method uses the dry-gas pseudo-pressure and an independent determination of the storativity ratio between the oil/gas region around the well and the original gas away from the well.
- Compositional simulation shows that the saturation profile during shut-in can be the same as the saturation profile at the time of shut-in for most drill stem testing and should be checked for production testing.
- When analysing a build-up below the dew point pressure, the storativity ratio between the condensate bank and the reservoir in the resulting radial composite behaviour must be calculated from the last pressure in the preceding drawdown.
- The storativity ratio is equal to the total compressibility ratio between the two zones, taking into account the mass exchange between the reservoir liquid and vapour phases at reservoir conditions.
- The mobility ratio between the zones is derived from effective permeability using the derivative stabilization and PVT data (assuming the derivative stabilizations can be identified in the derivative data)

Comments

The method presented by this paper is sufficient as long as the derivative stabilizations can be identified on the derivative plot.
10. SPE 121326 (2009)

Title: Predicting the Onset of Condensate Accumulation Near the Wellbore in a Gas Condensate Reservoir

Author: Krukrubo G. J. and Gringarten A.C.

Contribution to understanding of Gas Condensate Reservoirs
Developed a method for predicting when the effect of condensate accumulation is seen on the build up derivative plot of a lean gas condensate reservoir.

Objective(s) of the paper
To investigate the parameters that determines the onset time for the condensate effect to be seen on the build-up derivative plot.

Methodology used:
- Development of a one-dimensional radial grid simulation model (Eclipse 300).
- Definition of grid cell, time steps, fluid PVT properties, relative permeability curves and production rates.
- Validation of model with experimental and well test analysis data from a lean gas condensate field in the North Sea.
- Simulation of a single drawdown (DD) followed by a build-up (BU) with the bottomhole flowing pressure (BHFP) below the dew point pressure for a range of reservoir and fluid parameters.
- Analysis of the pressure transient data generated from the simulation and variation of the DD duration until the condensate bank can be identified on the BU derivative plot. This defined the onset time.
- The values of Fluid-And reservoir parameters at the onset time in the grid cell closest to the well were exported to Excel worksheet and analysed.
- Finally the onset times were plotted against the corresponding gas rates and the curves were matched with power equations.

Conclusions reached:
- Critical condensate saturation is not a criterion for the effect of condensate bank to be seen as a composite behaviour on the BU derivative plot.
- Mobility contrast is the critical parameter that controls the onset time for any given relative permeability curve.
- The critical value of mobility contrast for the condensate bank to be seen ranges from 1.7 to 2.1

Comments
- This study did not incorporate skin and reservoir heterogeneities and was limited to lean gas reservoir.
- An in-depth research should be carried out on rich gas condensates
11. SPE 121848 (2009)

Title: Well Test Dynamics in Rich Gas Condensate Reservoirs under Gas Injection

Author(s): Aluko, O.A. and Gringarten, A.C.

Contribution to understanding of Gas Condensate Reservoirs
Demonstrated the impact of condensate bank re-vaporization on well test behaviour as a result of re-pressurisation by gas injection.

Objective(s) of the paper:
To investigate the well test behaviour of rich gas condensate reservoirs below the dew point pressure and the impact of re-vaporization of the condensate bank due to re-pressurisation by gas injection.

Methodology used:
- Compositional simulation was used to study and characterise reservoir fluid dynamics and well test behaviour of wells in rich gas condensate reservoirs.
- The modified Peng Robinson eqn. of state was used to represent the thermodynamic properties of the fluids with parameters based on experimental data from an actual reservoir (MTGc, North Africa).
- Velocity dependent parameters matched to multi-rate well test data are included in the numerical modelling.
- Three alternating drawdowns and shut-ins were simulated with the flowing bottomhole pressure (FBHP) below the dew point pressure.
- Deconvolution was applied to the initial extended well test and to all the production build ups to diagnose the late time behaviour using the algorithm developed by von Schroeter et al., 2001.
- The deconvolved derivatives were constrained by the initial pressure of 5164 psi determined from Wireline formation tester (RCI) measurements.
- The deconvolved derivative of the production build ups were verified by simulating the reservoir description with a single phase voronoi grid simulator (Saphir from Kappa Engineering).

Conclusions reached:
- Retrograde condensation occurs below the dew point pressure in a rich condensate reservoir, and a condensate bank develops around the producing well. The near-wellbore liquid saturation reaches a maximum whereas the condensate bank continues to grow radially as the reservoir pressure declines.
- Productivity loss below the dew point pressure is primarily due to reduced effective gas permeability and can be overestimated if capillary number effects are not taken into account.
- Unlike in lean gas condensate reservoirs, the near-wellbore velocity stripping region is only visible at high rates in well test analysis data.
- Contrary to what happens in lean gas condensate reservoirs, the near wellbore fluid saturation below the dew point pressure in a build up is different from that at the end of the preceding drawdown, because of the significant differences in fluid properties and saturations.

Comments
The theoretical results presented in the paper are used to explain a series of production tests conducted in a rich gas condensate reservoir in North Africa.
Title: Comparative Well-Test Behaviours in Low-Permeability Lean, Medium-rich and Rich Gas-Condensate Reservoirs

Author(s): Kgogo, T. C. and Gringarten, A.C.

Contribution to understanding of Gas Condensate Reservoirs
Outlined the differences in well test behaviours in low permeability Lean, Medium-rich and rich gas condensate reservoirs.

Objective(s) of the paper:
To investigate and compare the well test behaviour of lean, medium-rich and rich gas condensate reservoirs below the dew point pressure.

Methodology used:
- Construction of 1-D radial compositional simulation model.
- Fluid PVT modelling using the modified Peng-Robinson equation of state (EOS).
- Compositional simulation runs and interpretation of simulated pressure data.
- Comparison of well test behaviours in the three types of gas condensate reservoirs.

Conclusions reached:
- During drawdown in medium-rich and rich gas condensate reservoirs, a condensate saturation develops around the well when pressure decreases below the dew point pressure, the size of which increases with production time, rate, fluid richness and decreasing reservoir permeability.
- Lean and medium-rich gas condensate fluids yield 3-mobility zone composite behaviour on a derivative plot whereas Lean and medium-rich gas condensate fluids yield three-mobility zone composite behaviours on a derivative plot whereas only two-mobility zones are created in the case of rich gas condensate fluids (Nc effects are not seen in practice).
- Actual well tests showed that dry gas reservoir behaviour may not be seen in production tests in low-permeability, medium-rich to rich gas condensate reservoirs because condensate banks could extend throughout the entire reservoir.
- Phase redistribution and liquid re-injection may dominate the test at early and middle times in drawdowns and build ups in low-permeability, medium-rich to rich gas condensate reservoirs due to low gas production rates.

Comments
This paper presented detailed differences in well test behaviours in low permeability gas condensates reservoirs.
APPENDIX B - Fluid Characterization

The complete composition of Fluid-A and B are shown in Table B-1 and Table B-2 respectively.

<table>
<thead>
<tr>
<th>Components</th>
<th>Wt %</th>
<th>Mol %</th>
<th>Components</th>
<th>Wt %</th>
<th>Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>N₂</td>
<td>0.27</td>
<td>0.38</td>
<td>C₁₅</td>
<td>1.82</td>
<td>0.35</td>
</tr>
<tr>
<td>H₂S</td>
<td>0.00</td>
<td>0.00</td>
<td>C₁₆</td>
<td>1.58</td>
<td>0.28</td>
</tr>
<tr>
<td>CO₂</td>
<td>1.05</td>
<td>0.93</td>
<td>C₁₇</td>
<td>1.65</td>
<td>0.27</td>
</tr>
<tr>
<td>C₁</td>
<td>25.84</td>
<td>62.76</td>
<td>C₁₈</td>
<td>1.42</td>
<td>0.22</td>
</tr>
<tr>
<td>C₂</td>
<td>9.83</td>
<td>12.74</td>
<td>C₁₉</td>
<td>1.12</td>
<td>0.17</td>
</tr>
<tr>
<td>C₃</td>
<td>6.77</td>
<td>5.99</td>
<td>C₂₀</td>
<td>1.13</td>
<td>0.16</td>
</tr>
<tr>
<td>iC₄</td>
<td>1.33</td>
<td>0.89</td>
<td>C₂¹</td>
<td>1.02</td>
<td>0.14</td>
</tr>
<tr>
<td>nC₄</td>
<td>3.57</td>
<td>2.40</td>
<td>C₂²</td>
<td>0.95</td>
<td>0.12</td>
</tr>
<tr>
<td>iC₅</td>
<td>1.53</td>
<td>0.83</td>
<td>C₂₃</td>
<td>0.86</td>
<td>0.11</td>
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<tr>
<td>nC₅</td>
<td>1.95</td>
<td>1.06</td>
<td>C₂₄</td>
<td>0.77</td>
<td>0.09</td>
</tr>
<tr>
<td>C₆</td>
<td>3.05</td>
<td>1.42</td>
<td>C₂₅</td>
<td>0.67</td>
<td>0.08</td>
</tr>
<tr>
<td>Benzene</td>
<td>0.33</td>
<td>0.16</td>
<td>C₂₆</td>
<td>0.62</td>
<td>0.07</td>
</tr>
<tr>
<td>C₇</td>
<td>3.85</td>
<td>1.57</td>
<td>C₂₇</td>
<td>0.57</td>
<td>0.06</td>
</tr>
<tr>
<td>Toluene</td>
<td>0.38</td>
<td>0.16</td>
<td>C₂₈</td>
<td>0.52</td>
<td>0.05</td>
</tr>
<tr>
<td>C₈</td>
<td>4.66</td>
<td>1.7</td>
<td>C₂₉</td>
<td>0.48</td>
<td>0.05</td>
</tr>
<tr>
<td>Ethyl-Benzene</td>
<td>0.07</td>
<td>0.03</td>
<td>C₃₀</td>
<td>0.44</td>
<td>0.05</td>
</tr>
<tr>
<td>Xylenes</td>
<td>0.77</td>
<td>0.28</td>
<td>C₃₁</td>
<td>0.4</td>
<td>0.04</td>
</tr>
<tr>
<td>C₉</td>
<td>3.05</td>
<td>0.98</td>
<td>C₃₂</td>
<td>0.35</td>
<td>0.03</td>
</tr>
<tr>
<td>C₁₀</td>
<td>3.48</td>
<td>1.01</td>
<td>C₃₃</td>
<td>0.32</td>
<td>0.03</td>
</tr>
<tr>
<td>C₁₁</td>
<td>2.72</td>
<td>0.72</td>
<td>C₃₄</td>
<td>0.28</td>
<td>0.02</td>
</tr>
<tr>
<td>C₁₂</td>
<td>2.24</td>
<td>0.54</td>
<td>C₃₅</td>
<td>0.26</td>
<td>0.02</td>
</tr>
<tr>
<td>C₁₃</td>
<td>2.27</td>
<td>0.51</td>
<td>C₃₆⁺</td>
<td>1.72</td>
<td>0.12</td>
</tr>
<tr>
<td>C₁₄</td>
<td>2.04</td>
<td>0.42</td>
<td>Total</td>
<td>100.00</td>
<td>100.00</td>
</tr>
</tbody>
</table>

Table B-1: Complete composition of Fluid-A (Courtesy: Aluko 2009)
Table B-2: Complete composition of Fluid-B (Courtesy: Thabo Kgogo 2005, MSc Thesis)

<table>
<thead>
<tr>
<th>Components</th>
<th>Wt %</th>
<th>Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>N_2</td>
<td>0.324</td>
<td>0.340</td>
</tr>
<tr>
<td>H_2S</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>CO_2</td>
<td>5.205</td>
<td>3.474</td>
</tr>
<tr>
<td>C_1</td>
<td>39.405</td>
<td>72.171</td>
</tr>
<tr>
<td>C_2</td>
<td>8.603</td>
<td>8.404</td>
</tr>
<tr>
<td>C_3</td>
<td>7.355</td>
<td>4.899</td>
</tr>
<tr>
<td>iC_4</td>
<td>1.390</td>
<td>0.702</td>
</tr>
<tr>
<td>nC_4</td>
<td>3.970</td>
<td>2.007</td>
</tr>
<tr>
<td>iC_5</td>
<td>1.599</td>
<td>0.651</td>
</tr>
<tr>
<td>nC_5</td>
<td>2.010</td>
<td>0.818</td>
</tr>
<tr>
<td>C_6</td>
<td>2.625</td>
<td>0.895</td>
</tr>
<tr>
<td>C_7</td>
<td>4.735</td>
<td>1.388</td>
</tr>
<tr>
<td>C_8</td>
<td>5.193</td>
<td>1.335</td>
</tr>
<tr>
<td>C_9</td>
<td>3.314</td>
<td>0.759</td>
</tr>
<tr>
<td>C_10</td>
<td>2.530</td>
<td>0.522</td>
</tr>
<tr>
<td>C_11</td>
<td>1.738</td>
<td>0.327</td>
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<tr>
<td>C_12</td>
<td>1.379</td>
<td>0.238</td>
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<tr>
<td>C_13</td>
<td>1.422</td>
<td>0.227</td>
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<tr>
<td>C_14</td>
<td>1.246</td>
<td>0.184</td>
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<tr>
<td>C_15</td>
<td>0.995</td>
<td>0.138</td>
</tr>
<tr>
<td>C_16</td>
<td>0.802</td>
<td>0.104</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Components</th>
<th>Wt %</th>
<th>Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>C_17</td>
<td>0.795</td>
<td>0.097</td>
</tr>
<tr>
<td>C_18</td>
<td>0.584</td>
<td>0.067</td>
</tr>
<tr>
<td>C_19</td>
<td>0.423</td>
<td>0.046</td>
</tr>
<tr>
<td>C_20</td>
<td>0.402</td>
<td>0.042</td>
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<tr>
<td>C_21</td>
<td>0.324</td>
<td>0.032</td>
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<tr>
<td>C_22</td>
<td>0.281</td>
<td>0.027</td>
</tr>
<tr>
<td>C_23</td>
<td>0.233</td>
<td>0.021</td>
</tr>
<tr>
<td>C_24</td>
<td>0.193</td>
<td>0.017</td>
</tr>
<tr>
<td>C_25</td>
<td>0.162</td>
<td>0.013</td>
</tr>
<tr>
<td>C_26</td>
<td>0.136</td>
<td>0.011</td>
</tr>
<tr>
<td>C_27</td>
<td>0.115</td>
<td>0.009</td>
</tr>
<tr>
<td>C_28</td>
<td>0.096</td>
<td>0.007</td>
</tr>
<tr>
<td>C_29</td>
<td>0.080</td>
<td>0.006</td>
</tr>
<tr>
<td>C_30</td>
<td>0.065</td>
<td>0.005</td>
</tr>
<tr>
<td>C_31</td>
<td>0.053</td>
<td>0.004</td>
</tr>
<tr>
<td>C_32</td>
<td>0.043</td>
<td>0.003</td>
</tr>
<tr>
<td>C_33</td>
<td>0.035</td>
<td>0.002</td>
</tr>
<tr>
<td>C_34</td>
<td>0.028</td>
<td>0.002</td>
</tr>
<tr>
<td>C_35</td>
<td>0.023</td>
<td>0.001</td>
</tr>
<tr>
<td>C_36^+</td>
<td>0.089</td>
<td>0.005</td>
</tr>
</tbody>
</table>

Total 100.00 100.00

For faster simulation run, the number of components in each fluid model were reduced by grouping the heavier components into pseudo components as shown in table 1 of the main report. **Fig. B-1** and **Fig. B-2** show the phase diagram of the fluid models after re-grouping.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

**Fig. B-1:** Phase diagram of Fluid-A

**Fig. B-2:** Phase diagram of Fluid-B
To ensure that the new fluid models are close replica of the original fluids, the behaviour was modelled and matched with the laboratory experiments namely:

1. Constant Composition Expansion (CCE)
2. Constant Volume Depletion (CVD).

This was achieved via regression. Figs. B-3 through B-6 show the match for Fluid-A and Fluid-B.

Fig. B-3: Constant composition expansion (CCE) match for Fluid-A

Fig. B-4: Constant volume depletion (CVD) match for Fluid-A
Fig. B-5: Constant composition expansion (CCE) for Fluid-B

Fig. B-6: Constant volume depletion (CVD) match for Fluid-B
APPENDIX C - Relative Permeability Modelling

The base case relative permeability curves were generated by matching the real field data for the rich gas condensate reservoir. The gas and condensate relative permeability curves as shown in Fig. 2 of the main report were generated using the Corey equations given by eqn. 1 and eqn. 2 in the main report. Table C-1 shows the real field data and the match for gas/condensate relative permeability.

Table C-1: Gas/condensate relative permeability match

<table>
<thead>
<tr>
<th>REAL FIELD RELPERM</th>
<th>RELPERM MATCH</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_g$, $k_{rg}$, $k_{org}$, $P_{cog}$</td>
<td>$S_g$, $k_{rg}$, $k_{org}$, $P_{cog}$</td>
</tr>
<tr>
<td>0, 0</td>
<td>0, 0, 0, 1</td>
</tr>
<tr>
<td>0.0012, 0.00014, 0.99846, 0</td>
<td>0.0012, 1.11482E-07, 0.99258, 0</td>
</tr>
<tr>
<td>0.003, 0.00044, 0.99516, 0</td>
<td>0.0015, 6.96765E-07, 0.99073, 0</td>
</tr>
<tr>
<td>0.006, 0.00138, 0.98488, 0</td>
<td>0.002, 2.78706E-06, 0.98765, 0</td>
</tr>
<tr>
<td>0.009, 0.003, 0.96700, 0</td>
<td>0.0025, 6.27089E-06, 0.98458, 0</td>
</tr>
<tr>
<td>0.012, 0.005, 0.94500, 0</td>
<td>0.003, 1.11482E-05, 0.98152, 0</td>
</tr>
<tr>
<td>0.03, 0.01755, 0.80000, 0</td>
<td>0.005, 4.4593E-05, 0.96932, 0</td>
</tr>
<tr>
<td>0.06, 0.03372, 0.64000, 0</td>
<td>0.0075, 0.00012, 0.95423, 0</td>
</tr>
<tr>
<td>0.09, 0.05127, 0.51000, 0</td>
<td>0.009, 0.00018, 0.94525, 0</td>
</tr>
<tr>
<td>0.12, 0.07136, 0.40500, 0</td>
<td>0.01, 0.00023, 0.93929, 0</td>
</tr>
<tr>
<td>0.15, 0.09353, 0.32000, 0</td>
<td>0.02, 0.00101, 0.88113, 0</td>
</tr>
<tr>
<td>0.18, 0.12032, 0.25000, 0</td>
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<td>0.21, 0.14988, 0.19300, 0</td>
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<tr>
<td>0.24, 0.18268, 0.14800, 0</td>
<td>0.09, 0.02208, 0.54053, 0</td>
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<tr>
<td>0.27, 0.21871, 0.11200, 0</td>
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</tr>
<tr>
<td>0.3, 0.25751, 0.08300, 0</td>
<td>0.15, 0.06188, 0.33098, 0</td>
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<td>0.33, 0.30277, 0.06000, 0</td>
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<td>0.36, 0.35289, 0.04250, 0</td>
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<tr>
<td>0.39, 0.40831, 0.03050, 0</td>
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<tr>
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<tr>
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<tr>
<td>0.591, 0.982, 0.00012, 0</td>
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<tr>
<td>0.594, 0.99175, 6.00E-05, 0</td>
<td>0.51, 0.72207, 0, 0</td>
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<td>0.597, 0.99736, 2.00E-05, 0</td>
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<td>0.5988, 0.99916, 1.00E-05, 0</td>
<td>0.57, 0.90234, 0, 0</td>
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<td>0.59994, 0.99980, 0, 0</td>
</tr>
<tr>
<td>0.6, 1, 0, 0</td>
<td>0.6, 1, 0, 0</td>
</tr>
</tbody>
</table>

The Corey parameters that define the base case scenario are shown in Table C-2.

Table C-2: Corey Parameters

<table>
<thead>
<tr>
<th>Corey Parameter</th>
<th>Match value</th>
<th>Corey Parameter</th>
<th>Match value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k_{rg}^{max}$</td>
<td>1</td>
<td>$S_{w}$</td>
<td>0.4</td>
</tr>
<tr>
<td>$k_{org}^{max}$</td>
<td>1</td>
<td>$\lambda_g$</td>
<td>2</td>
</tr>
<tr>
<td>$S_{gr}$</td>
<td>0.01</td>
<td>$\lambda_o$</td>
<td>3.1</td>
</tr>
<tr>
<td>$S_{wc}$</td>
<td>0.1</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The Corey equation for water relative permeability is given by eq. C-1 and eq. C-2 (Liu et al. 2001). Fig. C-1 shows the water/oil relative permeability curve. The water phase is assumed to be immobile for this research work.

\[
\begin{align*}
    k_{rw} &= 0.3 \left( \frac{S_w - S_{wc}}{1 - S_{wc}} \right)^2 \\
    k_{row} &= \left( \frac{1 - S_w - S_{wc}}{1 - S_{orw} - S_{wc}} \right)^2
\end{align*}
\]  

Fig. C-1: Water/oil phase relative permeability model
APPENDIX D - Simulation Model Validation

The simulation models were validated above the dew point pressure to ensure that the simulation results are consistent with the analytical results from well test analysis. The initial reservoir pressure was set at 5500 psia for Model A and 5000 psia for Model B to maintain simulation above the dew point pressure. A single drawdown and BU simulations (60 days) were run for the two models with gas production rate of 5MMscf/D. The simulated pressure transient data analysed with well test analysis software. The analytical results were compared with the input parameters to the models. Figs. D-1 and D-2 show the validation match for Fluid-A and Fluid-B. Table D-1 and Table D-2 show the comparison between the model input and analytical outputs. The differences are referenced to the model input.

Fig. D-1: Validation match for model A
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. D-2: Pressure history match (Fluid-A model)

Table D-1: Comparison of analytical outputs and model inputs (Model A)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Simulation Model Input</th>
<th>Well Test Analysis Output</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>$(P_0)$, psia</td>
<td>5500</td>
<td>5502.4</td>
<td>+ 0.04%</td>
</tr>
<tr>
<td>$k_h$, md-ft</td>
<td>2500</td>
<td>2440</td>
<td>- 2%</td>
</tr>
<tr>
<td>$k$, md</td>
<td>50</td>
<td>49</td>
<td>- 2%</td>
</tr>
<tr>
<td>$S$</td>
<td>0</td>
<td>0.5</td>
<td>+ 0.5</td>
</tr>
</tbody>
</table>
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Log-Log Match - Flow Period 2

**Fig. D-3**: Validation match for Model B

Simulation (Constant Skin) - Flow Period 2

**Fig. D-4**: Pressure transient history match (Fluid-B model)
Table D-2: Comparison of analytical outputs with model inputs (Model B)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Simulation Model Input</th>
<th>Well Test Analysis Output</th>
<th>Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>(P_{av}), psia</td>
<td>5000</td>
<td>5002</td>
<td>+ 0.04%</td>
</tr>
<tr>
<td>(k_h), mD-ft</td>
<td>2500</td>
<td>2354</td>
<td>- 6%</td>
</tr>
<tr>
<td>(k), mD</td>
<td>50</td>
<td>47</td>
<td>- 6%</td>
</tr>
<tr>
<td>(S)</td>
<td>0</td>
<td>0.28</td>
<td>+ 0.28</td>
</tr>
</tbody>
</table>

Fig. D-5: Validation of model (Fluid-B) incorporating permeability heterogeneity
Fig. D-6: Horner match for model validation with permeability heterogeneity

Fig. D-7: Pressure history match for model validation with permeability heterogeneity
APPENDIX E - Gas End-Point Relative Permeability Sensitivity

The $k_{rg}^{max}$ sensitivity was done by fixing the condensate end-point at 1 (base case) then multiple relative permeability curves were generated with $k_{rg}^{max} = 1, 0.8$ and 0.6 respectively as shown in Fig. E-1.

Table E-1 and Table E-2 show the results of the sensitivity analysis for Fluid-A and Fluid-B respectively.

### Table E-1: Results of $k_{rg}^{max}$ sensitivity (Fluid-A)

<table>
<thead>
<tr>
<th>$k_{rg}^{max}$</th>
<th>$Q$ (MMscf/d)</th>
<th>$T_{onset}$ (days)</th>
<th>$M_{initial}$ (md/cp)</th>
<th>$M_{onset}$ (md/cp)</th>
<th>$M_c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>15</td>
<td>200</td>
<td>1732</td>
<td>515</td>
<td>3.4</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>20</td>
<td>1740</td>
<td>508</td>
<td>3.4</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>1</td>
<td>1734</td>
<td>500</td>
<td>3.5</td>
</tr>
<tr>
<td>0.8</td>
<td>15</td>
<td>30</td>
<td>1382</td>
<td>436</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>6</td>
<td>1389</td>
<td>432</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>0.2</td>
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<td>13.5</td>
<td>6</td>
<td>1042</td>
<td>358</td>
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<tr>
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<td>15</td>
<td>1</td>
<td>1039</td>
<td>360</td>
<td>2.9</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>0.5</td>
<td>1040</td>
<td>360</td>
<td>2.9</td>
</tr>
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<td>1045</td>
<td>371</td>
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### Table E-2: Results of $k_{rg}^{\text{max}}$ sensitivity (Fluid-B)

<table>
<thead>
<tr>
<th>$k_{rg}^{\text{max}}$</th>
<th>$Q$ (MMscf/d)</th>
<th>$T_{\text{onset}}$ (days)</th>
<th>$M_{\text{initial}}$ (md/cp)</th>
<th>$M_{\text{onset}}$ (md/cp)</th>
<th>$M_{c}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>13.5</td>
<td>45</td>
<td>2856</td>
<td>1151</td>
<td>2.5</td>
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<td></td>
<td>15</td>
<td>15</td>
<td>2865</td>
<td>1140</td>
<td>2.5</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>7</td>
<td>2868</td>
<td>1126</td>
<td>2.5</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>0.5</td>
<td>2868</td>
<td>1137</td>
<td>2.5</td>
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<tr>
<td>0.8</td>
<td>13.5</td>
<td>10</td>
<td>2293</td>
<td>951</td>
<td>2.4</td>
</tr>
<tr>
<td></td>
<td>15</td>
<td>5</td>
<td>2295</td>
<td>949</td>
<td>2.4</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>0.8</td>
<td>2291</td>
<td>970</td>
<td>2.4</td>
</tr>
<tr>
<td>0.6</td>
<td>13.5</td>
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<td>1724</td>
<td>739</td>
<td>2.3</td>
</tr>
<tr>
<td></td>
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<td>0.5</td>
<td>1719</td>
<td>763</td>
<td>2.3</td>
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<tr>
<td></td>
<td>17.5</td>
<td>0.03</td>
<td>1721</td>
<td>790</td>
<td>2.2</td>
</tr>
</tbody>
</table>

**Figs. E-2 through E-4** show some of the normalised pressure change and derivative plots of the simulated pressure data for Fluid-A for different gas rates and $k_{rg}^{\text{max}}$ scenarios. **Figs. E-5 through E-7** show that of Fluid-B.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. E-3: 0.2-day onset (Fluid-A; 25MMscf/D and $k_{rg}^{max} = 0.8$)

Fig. E-4: 6-days onset (Fluid-A; 13.5MMscf/D and $k_{rg}^{max} = 0.6$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. E-5: 45 days onset (Fluid-B; 13.5MMscf/D and $k_r^{\max} = 1$)

Fig. E-6: 5 days onset (Fluid-B; 15MMscf/D and $k_r^{\max} = 0.8$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ Q = 24.516 t^{0.098} \]

\[ R^2 = 0.9778 \]

**Fig. E-7:** 0.5-day onset (Fluid-B; 15MMscf/D and \( k_{rg}^{max} = 0.6 \))

**Figs. E-8** through **E-10** show the gas production rate vs onset time plots for Fluid-A. **Fig. E-11** and **Fig. E-12** show the correlation of \( k_{rg}^{max} \) with coefficient \( C \) and exponent \( n \) respectively.

**Fig. E-8:** Gas rate vs. onset time (Fluid-A; \( k_{rg}^{max} = 1 \))
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ Q = 21.158 t^{-0.102} \]

\[ R^2 = 0.9995 \]

**Fig. E-9:** Gas rate vs. onset time (Fluid-A; \( k_{rg}^{max} = 0.8 \))

\[ Q = 15.82 t^{-0.099} \]

\[ R^2 = 0.9805 \]

**Fig. E-10:** Gas rate vs. onset time (Fluid-A; \( k_{rg}^{max} = 0.6 \))
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ C = -25.2 \left( k_{rg}^{\text{max}} \right)^2 + 61.97(k_{rg}^{\text{max}}) - 12.29 \]

\[ R^2 = 1 \]

Fig. E-11: Coefficient C vs. \( k_{rg}^{\text{max}} \) (Fluid-A)

\[ n = -0.1125(k_{rg}^{\text{max}})^2 + 0.1725(k_{rg}^{\text{max}}) + 0.036 \]

\[ R^2 = 1 \]

Fig. E-12: Exponent ‘\( n \)’ vs. \( k_{rg}^{\text{max}} \) (Fluid-A)
Figs. E-13 through E-15 show the drawdown rates vs onset time plots for Fluid-B. Fig. E-16 and Fig. E-17 show the correlation of $k_{rg}^{max}$ with coefficient $C$ and exponent $n$ respectively for Fluid-B.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

![Graph showing gas rate vs. onset time](image1)

**Fig. E-15:** Gas rate vs. onset time (Fluid-B; $k_{rg}^{max} = 0.6$)

\[ Q = 14.591 t^{-0.051} \]

\[ R^2 = 0.9974 \]

![Graph showing coefficient C vs. gas end-point relative permeability](image2)

**Fig. E-16:** Coefficient 'C' vs. $k_{rg}^{max}$ (Fluid-B)

\[ C = 35(k_{rg}^{max})^2 - 35.865(k_{rg}^{max}) + 23.51 \]

\[ R^2 = 1 \]
Mobility contrast as the critical parameter
The mobility contrast at onset time is approximately constant for a given relative permeability curve.
Figs. E-18 through E-23 illustrate constant the mobility contrast at onset time for at different gas rates, for a given relative permeability curve.
Fig. E-19: Mobility contrast at onset time (Fluid-A; $k_{rg}^{max} = 0.8$)

Fig. E-20: Mobility contrast at onset time (Fluid-A; $k_{rg}^{max} = 0.6$)
Fig. E-21: Mobility contrast at onset time (Fluid-B; $k_{rg}^{max} = 1$)

Fig. E-22: Mobility contrast at onset time (Fluid-B; $k_{rg}^{max} = 0.8$)
Figs. E-18 – E-23 confirm the fact that mobility contrast is the critical parameter that determines the onset of condensate banking on the BU derivative response for a given relative permeability curve. For the same relative permeability curve, the mobility at onset time is approximately constant for different rates. Hence the total mobility of the near-wellbore region will decline by the factor equal to the mobility contrast before the effect of condensate accumulation can be seen in the BU derivative response.
APPENDIX F - Condensate End-Point Relative Permeability Sensitivity

The $k_{\text{ro}}^\text{max}$ sensitivity was done by fixing the gas end-point at 0.8. Multiple relative permeability curves were generated with $k_{\text{ro}}^\text{max} = 1, 0.8$ and 0.6 respectively (Fig. F-1).

Fig. F-1: Multiple relative permeability curves ($k_{\text{ro}}^\text{max}$ sensitivity)

Table F-1 and Table F-2 show the results of the sensitivity analysis for Fluid-A and Fluid-B respectively.

Table F-1: Results of $k_{\text{ro}}^\text{max}$ sensitivity (Fluid-A)

<table>
<thead>
<tr>
<th>$k_{\text{ro}}^\text{max}$</th>
<th>$Q$ (MMscf/d)</th>
<th>$T_{\text{onset}}$ (days)</th>
<th>$M_{\text{init}}$ (md/cp)</th>
<th>$M_{\text{onset}}$ (md/cp)</th>
<th>$M_c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>15</td>
<td>30</td>
<td>1382</td>
<td>436</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>6</td>
<td>1389</td>
<td>432</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td>25</td>
<td>0.2</td>
<td>1389</td>
<td>434</td>
<td>3.2</td>
</tr>
<tr>
<td>0.8</td>
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<td>36</td>
<td>1387</td>
<td>400</td>
<td>3.5</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>8</td>
<td>1390</td>
<td>398</td>
<td>3.5</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>0.5</td>
<td>1386</td>
<td>400</td>
<td>3.5</td>
</tr>
<tr>
<td>0.7</td>
<td>15</td>
<td>45</td>
<td>1387</td>
<td>381</td>
<td>3.6</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>10</td>
<td>1390</td>
<td>380</td>
<td>3.7</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>1</td>
<td>1390</td>
<td>380</td>
<td>3.7</td>
</tr>
</tbody>
</table>
Table F-2: Results of $k_{ro}^{\text{max}}$ sensitivity (Fluid-B)

<table>
<thead>
<tr>
<th>$k_{ro}^{\text{max}}$</th>
<th>Q (MMscf/d)</th>
<th>$T_{\text{onset}}$ (days)</th>
<th>$M_{\text{initial}}$ (md/cp)</th>
<th>$M_{\text{onset}}$ (md/cp)</th>
<th>$M_c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>13.5</td>
<td>10</td>
<td>2293</td>
<td>951</td>
<td>2.4</td>
</tr>
<tr>
<td>15</td>
<td>15</td>
<td>5</td>
<td>2295</td>
<td>949</td>
<td>2.4</td>
</tr>
<tr>
<td>17.5</td>
<td>17.5</td>
<td>0.8</td>
<td>2291</td>
<td>970</td>
<td>2.4</td>
</tr>
<tr>
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<td>8</td>
<td>2295</td>
<td>887</td>
<td>2.6</td>
</tr>
<tr>
<td>17.5</td>
<td>2</td>
<td>2</td>
<td>2291</td>
<td>897</td>
<td>2.6</td>
</tr>
<tr>
<td>20</td>
<td>0.8</td>
<td>2293</td>
<td>892</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.7</td>
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<td>11</td>
<td>2295</td>
<td>860</td>
<td>2.7</td>
</tr>
<tr>
<td>17.5</td>
<td>3</td>
<td>2291</td>
<td>865</td>
<td></td>
<td>2.6</td>
</tr>
<tr>
<td>20</td>
<td>1</td>
<td>2293</td>
<td>868</td>
<td></td>
<td>2.6</td>
</tr>
</tbody>
</table>

Figs. F-2 through F-5 shows some of the BU normalised pressure change and derivative plots of the simulated pressure data for Fluid-A for different gas rates and $k_{ro}^{\text{max}}$ scenarios. Figs. F-6 through F-9 shows the derivative plots for Fluid-B.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. F-3: 36-days onset (Fluid-A; 15MMscf/D and $k_{rog}^{max} = 0.8$)

Fig. F-4: 45-days onset (Fluid-A; 15MMscf/D and $k_{rog}^{max} = 0.7$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. F-5: 1-day onset (Fluid-A; 20MMscf/D and $k_{rog}^{max} = 0.7$)

Fig. F-6: 8-days onset (Fluid-B; 15MMscf/D and $k_{rog}^{max} = 0.8$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. F-7: 2-days onset (Fluid-B; 17.5MMscf/D and \( k_{rog}^{max} = 0.8 \))

Fig. F-8: 11-days onset (Fluid-B; 15MMscf/D and \( k_{rog}^{max} = 0.7 \))
Fig. F-9: 3-days onset (Fluid-B; 17.5MMscf/D and $k_{rog}^{max} = 0.7$)

Fig. F-10 and Fig. F-11 show the gas rate vs onset time plots for Fluid-A. Fig. F-12 and Fig. F-13 show the correlation of $k_{rog}^{max}$ with coefficient $C$ and exponent $n$ respectively.

Fig. F-10: Gas rate vs. onset time (Fluid-A; $k_{rog}^{max} = 0.8$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ Q = 20.211 t^{-0.074} \]

\[ R^2 = 0.974 \]

Fig. F-11: Gas rate vs. onset time (Fluid-A; \( K_{\text{rog}}^{\text{max}} = 0.7 \))

\[ C = 58.683(K_{\text{rog}}^{\text{max}})^2 - 96.605(K_{\text{rog}}^{\text{max}}) + 59.08 \]

\[ R^2 = 1 \]

Fig. F-12: Coefficient 'C' vs. \( K_{\text{rog}}^{\text{max}} \) (Fluid-A)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ n = 0.9167(K_{\text{rog max}})^2 - 1.465 (K_{\text{rog max}}) + 0.6503 \]

\[ R^2 = 1 \]

\[ n = 0.9167(K_{\text{rog max}})^2 - 1.465 (K_{\text{rog max}}) + 0.6503 \]

**Fig. F-13:** Exponent ‘\( n \)’ vs. \( k_{\text{rog max}} \) (Fluid-A)

**Fig. F-14** and **Fig. F-15** show the gas rate vs onset time plots for Fluid-B. **Fig. F-16** and **Fig. F-17** show the correlation of \( k_{\text{rog max}} \) with coefficient C and exponent n respectively.
Fig. F-15: Gas rate vs. onset time (Fluid-B; $k_{rog}^{max} = 0.7$)

\[ Q = 19.988 \ t^{0.12} \]

\[ R^2 = 1 \]

Fig. F-16: Coefficient ‘C’ vs. $k_{rog}^{max}$ (Fluid-B)

\[ C = -12.183(K_{rog}^{max})^2 + 11.475(K_{rog}^{max}) + 17.926 \]

\[ R^2 = 1 \]
Mobility contrast as the critical parameter

The mobility contrast at onset time is approximately constant for a given relative permeability curve. **Figs. F-18 through F-23** show constant mobility contrast at onset time for at different gas rates, for a given relative permeability curve:
Fig. F-19: Mobility contrast at onset time (Fluid-A; $k_{rog}^{max} = 0.8$)

Fig. F-20: Mobility contrast at onset time (Fluid-A; $k_{rog}^{max} = 1$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

**Fig. F-21:** Mobility contrast at onset time (Fluid-B; $k_{\text{org}}^{\text{max}} = 0.7$)

**Fig. F-22:** Mobility contrast at onset time (Fluid-B; $k_{\text{org}}^{\text{max}} = 0.8$)
Figs. F-18 – F-23 show that mobility contrast is the critical parameter that controls the onset of condensate banking on BU derivatives for a given relative permeability curve. For the same relative permeability curve, the mobility at onset time is approximately constant even though the gas rates are different. Hence the total fluid mobility in the near-wellbore region has to decrease by the factor equal to the mobility contrast before condensate banking can be seen on BU derivatives.
**APPENDIX G - Critical Condensate Saturation Sensitivity**

The critical condensate saturation ($S_{oc}$) sensitivity was done by generating multiple relative permeability curves with $S_{oc} = 0.1$ (base case), 0.15 (+15%) and 0.08 (-20%) respectively as shown in Fig. G-1. The gas and condensate end-points were set at 0.8 and 1 respectively in all cases.

![Multiple relative permeability curves (S_{oc} sensitivity)](image)

**Table G-1 and Table G-2** show the results of the sensitivity analysis for Fluid-A and Fluid-B respectively.

**Table G-1: Results of $S_{oc}$ Sensitivity (Fluid-A)**

<table>
<thead>
<tr>
<th>$S_{oc}$ (fraction)</th>
<th>Q MMscf/d</th>
<th>$T_{onset}$ (days)</th>
<th>$M_{initial}$ (md/cp)</th>
<th>$M_{onset}$ (md/cp)</th>
<th>$M_c$</th>
</tr>
</thead>
<tbody>
<tr>
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<td>1381</td>
<td>379</td>
<td>3.6</td>
</tr>
<tr>
<td></td>
<td>15</td>
<td>8</td>
<td>1382</td>
<td>378</td>
<td>3.7</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>1</td>
<td>1384</td>
<td>379</td>
<td>3.7</td>
</tr>
<tr>
<td>0.1</td>
<td>15</td>
<td>30</td>
<td>1382</td>
<td>436</td>
<td>3.2</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>6</td>
<td>1389</td>
<td>432</td>
<td>3.2</td>
</tr>
<tr>
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<td>25</td>
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<td>1389</td>
<td>434</td>
<td>3.2</td>
</tr>
<tr>
<td>0.08</td>
<td>15</td>
<td>45</td>
<td>1382</td>
<td>459</td>
<td>3.0</td>
</tr>
<tr>
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<td>456</td>
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<td>1386</td>
<td>456</td>
<td>3.0</td>
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</table>
Table G-2: Results of $S_{oc}$ Sensitivity (Fluid-B)

<table>
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<tr>
<th>$S_{oc}$ (fraction)</th>
<th>Q MMscf/d</th>
<th>$T_{onset}$ (days)</th>
<th>$M_{init}$ (md/cp)</th>
<th>$M_{onset}$ (md/cp)</th>
<th>$M_z$</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.15</td>
<td>10</td>
<td>9</td>
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<tr>
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<td>951</td>
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<td>15</td>
<td>5</td>
<td>2295</td>
<td>949</td>
<td>2.4</td>
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<tr>
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<td>17.5</td>
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<td>2291</td>
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<td>1010</td>
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<td>7</td>
<td>2288</td>
<td>1007</td>
<td>2.3</td>
</tr>
<tr>
<td></td>
<td>17.5</td>
<td>1</td>
<td>2291</td>
<td>1021</td>
<td>2.2</td>
</tr>
</tbody>
</table>

Figs. G-2 through G-5 show some of the BU normalised pressure change and derivative plots of the simulated pressure data for Fluid-A for different gas rates and $S_{oc}$ scenarios. Figs. G-6 through G-9 show the derivative plots for Fluid-B.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. G-3: 1-day onset (Fluid-A; 17.5MMscf/D and $S_{oc} = 0.15$)

Fig. G-4: 45-days onset (Fluid-A; 15MMscf/D and $S_{oc} = 0.08$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. G-5: 1-day onset (Fluid-A; 20MMscf/D and $S_{oc} = 0.08$)

Fig. G-6: 9-days onset (Fluid-B; 10MMscf/D and $S_{oc} = 0.15$)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

Fig. G-7: 1-day onset (Fluid-B; 15MMscf/D and $S_{oc} = 0.15$)

Fig. G-8: 13-days onset (Fluid-B; 13.5MMscf/D and $S_{oc} = 0.08$)
**Fig. G-9**: 7-days onset (Fluid-B; 15MMscf/D and $S_{oc} = 0.08$)

**Fig. G-10** and **Fig. G-11** show the gas rate vs onset time plots for Fluid-A. **Fig. G-12** and **Fig. G-13** show the correlation of $S_{oc}$ with coefficient $C$ and exponent $n$ respectively.
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ C = -1803.7 \left(S_{oc}\right)^2 + 378.17S_{oc} + 1.3783 \]

\[ R^2 = 1 \]

**Fig. G-11:** Gas rate vs. onset time (Fluid-A; \( S_{oc} = 0.08 \))

\[ Q = 20.088 t^{-0.076} \]

\[ R^2 = 0.9971 \]

**Fig. G-12:** Coefficient ‘\( C \)’ vs \( S_{oc} \) (Fluid-A)
Predicting when Condensate Banking becomes visible on Build-up Derivatives

\[ n = -26(S_{oc})^2 + 5.98(S_{oc}) - 0.236 \]

**Fig. G-13:** Exponent 'n' vs \( S_{oc} \) (Fluid-A)

**Fig. G-14** and **Fig. G-15** show the gas rate vs onset time plots for Fluid-B. **Fig. G-16** and **Fig. G-17** show the correlation of \( S_{oc} \) with coefficient C and exponent n respectively.

\[ Q = 15.373 t^{-0.188} \]

**Fig. G-14:** Gas rate vs. onset time (Fluid-B; \( S_{oc} = 0.15 \))
Predicting when Condensate Banking becomes visible on Build-up Derivatives

![Graph](image)

**Fig. G-15:** Gas rate vs. onset time (Fluid-B; \( S_{oc} = 0.08 \))

**Fig. G-16:** Coefficient 'C' vs. \( S_{oc} \) (Fluid-B)

\[
Q = 17.611 t^{-0.096}
\]

\[
C = -246.43(S_{oc})^2 + 24.707(S_{oc}) + 17.212
\]

\( R^2 = 0.9672 \)
Mobility contrast as the critical parameter

The mobility contrast at onset time is approximately constant for a given relative permeability curve. Figs. G-18 and G-19 illustrate constant mobility contrast at onset time for at different gas rates for a given relative permeability curve:

Fig. G-17: Exponent 'n' vs. $S_{oc}$ (Fluid-B)

Fig. G-18: Mobility contrast at onset time (Fluid-A; $S_{oc} = 0.1$)
Fig. G-19: Mobility contrast at onset time (Fluid-B; $S_{oc} = 0.1$)
APPENDIX H - Eclipse Simulation Codes

---=================================================================================================
-- CASE-1:: RICH CONDENSATE RADIAL GRID MODEL
--=================================================================================================
RUNSPEC
TITLE
    CASE-1 :: RADIAL GRID – RICH CONDENSATE

DIMENS
    120 1 1 /

ISGAS

WATER

RADIAL

VELDEP
    1 1 0 1 /

FIELD

FULLIMP

EQLDIMS
    5*

TABDIMS
    6*

WELLDIMS
    7 6 2 4 /

NUPCOL
    4 /

-- Eqn. of State – Peng-Robinson –
EOS
    PR /

-- Number of Components –
COMPS
    19 /

START
    01 ‘JAN’ 2001 /

ystack
    100 /

MESSAGES
    11* 5 /

---=================================================================================================
GRID
---=================================================================================================
INIT
ECHO
Simulation codes (continued)

-- Inner radius ft

INRAD
0.354 /

-- Vector of cell dimensions in R-direction

<p>| | | | | | | | |</p>
<table>
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</table>

/

-- Vector of cell dimensions in THT-direction

DTHETAV
360 /

-- Dimensions of cells in Z-direction

DZV
50 /

EQUALS
TOPS 10000 /
PORO 0.13 /
/

BOX
1 120 1 1 1 1 /

PERMR
120*100 /

-- OUTPUT OF GRID DATA IN BOTH GLOBAL AND LOCAL SYSTEMS

RPTGRID
/
RPTGRIDL/
/

PROPS
--------
THE PROPS SECTION DEFINES THE REL. PERMEABILITIES, CAPILLARY
PRESSURES, AND THE PVT PROPERTIES OF THE RESERVOIR FLUIDS

--- Fluid Model

INCLUDE
'./INCLUDE/MLN1_DST1-1Bcomp2.PVO' /
Simulation codes (continued)

--WATER-OIL RELATIVE PERMEABILITY

INCLUDE
'../INCLUDE/MLN_SWOF_Krw-mod1.txt' /

-- GAS-OIL RELATIVE PERMEABILITY
INCLUDE
'../RELPERM_SCENARIOS/SGOF_krgmax=0.8.txt' /

DENSITY
-- Oil Water Gas
40.0000 77.1600 0.001 /

-- Water PVT Properties
-- REF. PRES. REF. FVF COMPRESSIBILITY REF VISCOSITY VISCOSIBILITY

PVTW
5500 1.0352 2.06E-06 0.3 0.0 /

-- Rock Compressibility
ROCK
5500 4.69E-6/

INCLUDE
'../INCLUDE/VELDEP_Nc1.txt' /

-- ---------------------------------------------------------------------

REGIONS
-- ---------------------------------------------------------------------

RPTREGS
/

-- ---------------------------------------------------------------------

SOLUTION
-- ---------------------------------------------------------------------

-------- THE SOLUTION SECTION DEFINES THE INITIAL STATE OF THE SOLUTION
-------- VARIABLES (PHASE PRESSURES, SATURATIONS AND GAS-OIL RATIOS)
-- ---------------------------------------------------------------------

EQUIL
-- DATUM DATUM OWC OWC GOC GOC
-- DEPTH PRESS DEPTH PCOW DEPTH PCOG

10012.5 5500 12000 0 11500 0 3* 1 /

-- ---------------------------------------------------------------------

SUMMARY
-- ---------------------------------------------------------------------

RUNSUM
-- Simulation results (Grid cell Outputs)

INCLUDE
'../INCLUDE/Sim-Outputs_2.txt' /
### Simulation codes (continued)

**SCHEDULE**

---

--- THE SCHEDULE SECTION DEFINES THE OPERATIONS TO BE SIMULATED

---

### RPTPRINT

```
7*0 1 5*0 /
```

### RUNSUM

### RPTONLY

---

-- LOCAL WELL SPECIFICATION DATA

```
WELLSPEC
-- Well Well I J Ref BHP Preferred
-- Name Group Depth Phase
W1 P1 1 1 10012.5 GAS /
```

---

-- LOCAL COMPLETION SPECIFICATION DATA

```
COMPDAT
-- WELL I J K1 K2 K-STATUS SAT/TRANS INDIAM KH
-- NAME W1 1 1 1 1 OPEN 2* 0.708 1* 0/
```

---

-- DRAWDOWN SCHEDULE

```
WELLPROD
-- NAME CTRL ORAT WRAT GRAT LRAT BHP
W1 GAS 1* 1* 5000 1* 20 /
```

---

INCLUDE
```
'. ../INCLUDE/Time-10days.txt' /
```

---

### BU SCHEDULE

```
WELLPROD
-- NAME CTRL ORAT WRAT GRAT LRAT BHP
W1 GAS 0 0 0 0 20 /
```

---

INCLUDE
```
'. ../INCLUDE/Time-10days.txt' /
```

---

END

---