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A Novel Methodology for the Analysis of Well Test Responses in Gas Condensate Reservoirs

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Abstract

Single-phase analysis based on pseudopressure has been extensively used in the oil industry to analyse well test data from gas condensate reservoirs. However, the presence of the two-fluid system which forms when the pressure drops below the dew-point requires advanced techniques to derive accurate skin values. This quantity contains contributions from the mechanical, non-Darcy and liquid drop-out components. Many remedial well treatments (acidification, hydraulic fractures, etc) have been designed on such incorrect analysis, the resulting lack of treatment success leading to an unnecessary increase in operational cost. The aim of this study is to develop a full understanding of multiphase flow effects, to establish a systematic methodology using the two-phase pseudopressure function and to obtain accurate results from gas condensate well test analysis.

This work uses the steady-state, two-phase pseudopressure in the same manner as the familiar single-phase pseudopressure analogue.

A 1D compositional simulation model was used to generate the input data for the well test interpretation, special attention being paid to the time step and grid size distribution to avoid numerical truncation errors.

The mechanical skin used varies from negative values (wells with fractures) to positive values (wells with formation damage). A correlation between the skin value obtained from the two-phase pseudopressure analysis and the mechanical skin was derived. This allows the reservoir engineers to make the key discriminations between mechanical skin and liquid drop-out skin.

The approach used here was also extended to generate a general understanding of the production behaviour of condensate production wells e.g. fluid, velocity and relative permeability effects on the resulting pressure drops created by condensate accumulation near to the wellbore. This will find application to well design e.g. the conditions under which horizontal wells can eliminate a condensate bank near to the wellbore can be confidently predicted.

Introduction

(High pressure, high temperature) gas condensate reservoirs are currently being developed in greater numbers. These types of reservoirs show a complex behaviour attributable to the presence of a two-fluid system once the pressure drops below the dew point. Liquid dropout caused by retrograde condensation leads to a condensate bank building-up around the producing wells. The growing condensate bank progressively impedes gas flow into the well.. The effect of a condensate blockage region depends on a number of reservoir parameters; such as formation's relative permeability, the fluid properties, etc.

Fluid properties and relative permeability data are essential in order to diagnosis and analyse a well test accurately. However there are many challenges involved on sampling gas condensate reservoirs. Accurate simulation of liquid dropout process is based on Equation of State (EOS). Without proper PVT data, the EOS can be very uncertain and the resulting predictions will be inaccurate.

The measurement of relative permeability for a gas condensate reservoir is not an easy task; the retrograde liquid initially forms in the vicinity of the producing wells, where the greatest rate of pressure reduction is present, causing a gas phase relative permeability reduction. It is important that experimental procedures to generate the relative permeability data in the laboratory be representative of the condensing process that occurs in such reservoir. Conventional gas/oil drainage relative permeability measurements have been commonly used to represent gas condensate reservoir behaviour. However there are important differences between the resultant fluid distributions; oil increases from zero saturation in the condensate case compared with oil decreasing

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from 100% as in conventional SCAL measurements. In addition, Danesh et al demonstrated that steady-state relative permeability carried out using gas condensate fluids are sensitive to flow rate - both gas and condensate relative permeability increase as the flow velocity increased.

An understanding of the condensate banking process and condensate mobility is essential in predicting well behaviour and the performance of gas condensate reservoirs.

Jones and Raghavan in 1988 examine the transient behaviour of a condensate well (drawdown and buildup) using a (1D) compositional simulation model with a simple three components gas condensate mixture. They showed that the pseudopressure presented by Fussell is accurate at all times during depletion. However, the integral must be evaluated using pressures and saturations as a function of radius for a given time during depletion. This theoretical tool is not very practical since it is necessary to do a compositional simulation to know the pressures and saturations at a given time in depletion. Jones and Raghavan also showed that a pseudopressure function that incorporates the influence of changes in relative permeability and fluid properties through the "steady-state" theory may be used to estimate formation flow capacity (kh) and skin factors. Raghavan et al. evaluated the shape of pressure build-up records for a wide variety of conditions and showed that their two-phase analogue works best when the differences between the initial reservoir and dew point pressures and between the dew point and bottomhole pressures are large. A stabilized bank of fluid with a very small transition zone around the wellbore forms in these circumstances.

Fevang in (1995) developed a new pseudopressure approach using a pressure saturation relationship calculated separately in each region. This approach was an extension of pseudopressure method proposed by Evinger and Muskat for solution gas drive oil wells. The pseudopressure integral was divided into three parts, corresponding to three flow regions:

Region 1: an inner near-wellbore region where both gas and oil flow simultaneously.
Region 2: a region of condensate build-up where only gas is flowing.
Region 3: a region containing single-phase (original) reservoir gas.

The main objective of this work is:

(1) to develop a good understanding on how to use the two-phase pseudopressure method to analyse well test responses in a gas condensate reservoir and
(2) to establish a systematic methodology to obtain the most accurate results from this analysis.

Background

Gas Condensate Reservoirs. Various types of reservoirs can be classified by the location of their initial reservoir pressure and temperature with respect to the two-phase, gas-liquid region. Gas condensate reservoirs are distinguished by two characteristics. Firstly, a liquid phase can condense during isothermal pressure depletion (retrograde behavior). Secondly, this liquid revapourizes with further pressure depletion. Figure 1 shows that the condensation starts at the dew point pressure shown as point D1. The volume of liquid increasing to approximately 10% at point R after which revapourisation results in a decrease in the liquid volume with continued reduction in pressure.

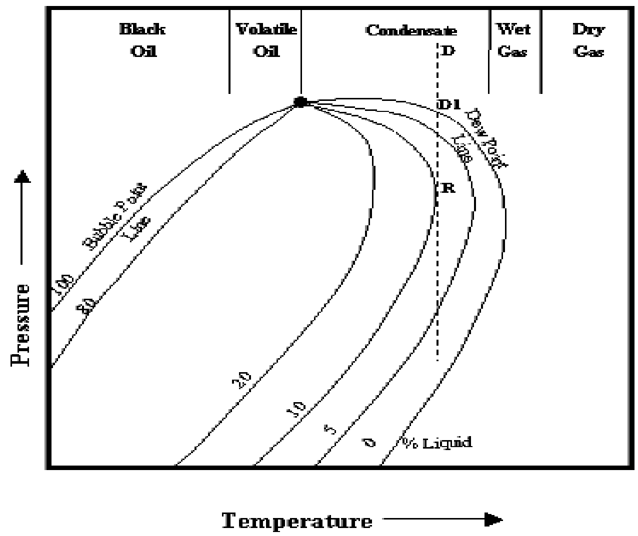


Figure 1: Phase Diagram for a Condensate Reservoir.

Gas Condensate Flow. A three-region model has been frequently used to characterise gas condensate flow,. The first region is the outer part of the reservoir; only the gas phase is present due to the pressure being above the dewpoint. The second region has a pressure below dewpoint, but the condensate formed remains immobile due to its low saturation. The third region is near the wellbore with both gas and condensate flowing. The existence of the third zone is important as it reduces the reduction in well productivity due to the liquid drop out.

This three-region model has formed the basis for many gas condensate flow studies. During reservoir depletion the condensate saturation increases from zero and is present in the second and third regions.

Santa Barbara Reservoir

The Santa Barbara field, operated by Petroleos de Venezuela, S.A (PDVSA), is located in the North Monagas Area, Eastern Venezuela Basin. The fluid column is complex with an extreme vertical compositional variation. It shows, from top to bittom, a low yield condensate, a near critical fluid, a volatile oil and finally, a highly undersaturated oil. A clear oil-gas contact is not present, instead a transition zone is observed where gas and oil properties cannot be distinguished. High-pressure produced-gas injection has been implemented to increase reserves and minimize rapid reservoir pressure decline.

The 2500 feet thick Naricual and Cretaceo formations are the main producers. These complex reservoirs are characterized by numerous faults with upto 1000 ft. vertical displacement.

Pressure analysis data suggest that some of these faults are sealing, causing reservoir compartmentalization. **Table 1** summarizes the main reservoir parameters

Parameters	Values
Initial Pressure, psia	11900
Actual Pressure, psia	7600
Saturation Pressure, psia	3500 – 8500
Reservoir Temperature, ºF	310 – 280
Average Depth, feet	16500
Datum, feet	15800
Average Porosity, %	5 - 15
Permeability Range, md	1 -300
Average °API	29 - 36

Table 1: Santa Barbara Reservoir Parameters

Pressure Analysis

Well Test Analysis Procedure. This study aims to establish a systematic methodology for analysing production well test pressure data in gas condensate reservoirs. A three-phase, one-dimensional model was used to generate simulation results. Different synthetic features were simulated in order to illustrate the build-up pressure response in gas condensate reservoirs.

The pressure information was analysed using PanSystem supplied by Edinburgh Petroleum Services. The fluid parameters required by the well test pressure analysis package were calculated by the program PVTi (supplied by Geoquest). Both these packages used the Peng-Robison equation of state. The reservoir gas specific gravity γ_g, API, CGR were calculated using the produced fluid composition generated with the Eclipse 300 package, also supplied by Geoquest.

Single Phase Analysis. Initially a conventional dry gas well test analysis (using PanSystem) was performed using single phase gas pseudopressure {m(p)} based on the tuned fluid properties described above:

$$m(p) = 2\int_{p_b}^{p} \frac{\rho_g}{\mu_g} dp$$

Data Analysis. Diagnostic. For diagnostic purposes, two main methods were used to identify the flow regimes and reservoir parameters:
Line fitting (using various analysis plot such as Cartesian, Semilog, log-log).
Curve Matching, using type curves.
The derivative log-log plot of the pressure build-up response in the single-phase analysis showed a clear radial composite model as expected for the base case model with the well bottom hole flowing pressure below the dew-point pressure.An inner cylindrical region with lower conductivity due to the liquid drop out effect and an outer region of higher conductivity (single-phase zone), were identified (**Figure 2**).

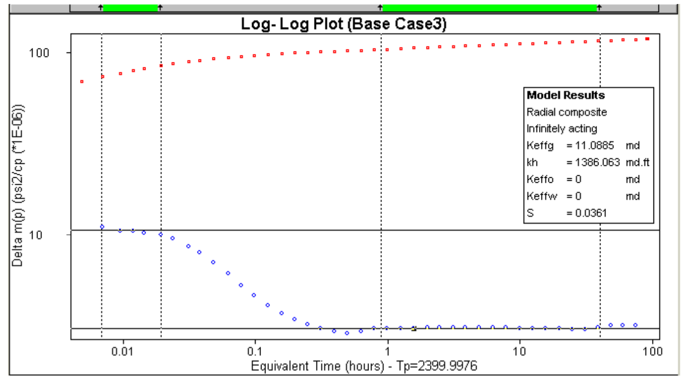


Figure 2: Log-Log Plot Base Case 3. Single-Phase Analysis.

Flow regime definition (FR). The following flow regimes were identified using the line fitting analysis of the log-log plot:

Inner Radial flow regime: corresponding to the early time region (ETR). A radial flow regime was identified by fitting a horizontal line (zero slope) to the derivative pressure response (**Figure 2**). The inner region permeability was calculated from the position of this line. This permeability value represents the reduced permeability value caused by the condensate accumulation near to the wellbore region.

Outer Radial flow regime in **the middle time region: A** zone of greater mobility away from the wellbore was found. A zero slope line was also fitted to the derivative data points representing the mobility ratio between the outer and inner zones. The resulting permeability value for this region is the gas effective permeability in the single-phase zone i.e. the absolute permeability multiplied by the gas relative permeability at the connate water saturation value. ($k_{effg} = K{*}k_{rg@Swi}$).

It was observed that the pressure derivative roll over, due to the change from two-phase flow to single-phase gas behaviour, occurred at a lower pressure than the dew point pressure value. This is possibly related to the selected set of gas relative permeability curves. These showed that the effect of a small amount of condensate was that the gas relative permeability was hardly noticeable until a minimum value of oil saturation was reached.

Type Curve Matching. The type curve matching was used as complement to the derivative pressure analysis.

Specialized Analysis. The semilog or Horner Plot (where the previous defined periods are automatically selected), allowed the calculation of the permeability and skin factor from the slope and the intercept of the straight line fitted to the radial flow regime points (**Figure 3**). The total skin, including any liquid drop out skin, is calculated from the outer region zone using the single-phase approach. From this plot, the initial pressure of the reservoir was determined by extrapolating the last data points on the build-up period. In each of the simulated cases this initial pressure was identical to the value input into the simulation model.

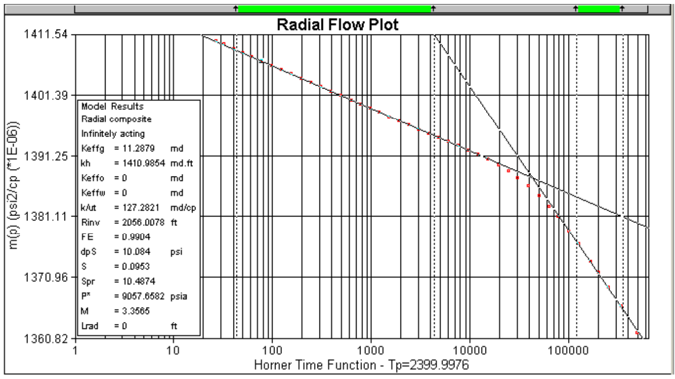


Figure 3: SemiLog Plot. Base Case 3. Single-Phase Analysis.

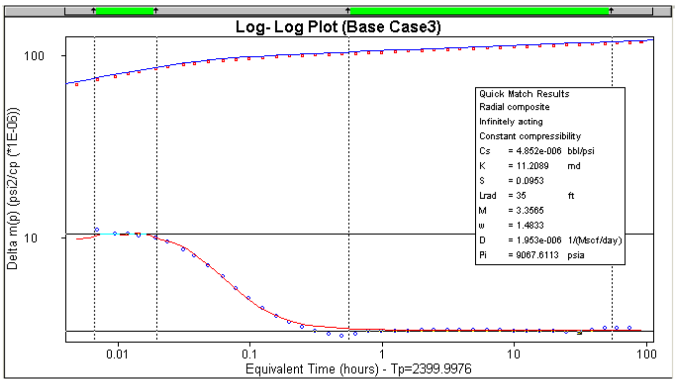


Figure 4: Log-Log Plot Base Case 3. Single-Phase Analysis. Auto Match Results.

Simulation. This stage was carried out in order to confirm that the chosen radial composite reservoir model calculated the reservoir parameters that are consistent with the simulation input data (**Figure 4**).

Two Phase Pseudopressure Analysis. A two-phase pseudopressure analysis was carried out following the single-phase analysis. This analysis required a two-phase pseudopressure function to be computed and imported into PanSystem. The two-phase analogue used is given by:

$$m(p) = 2\int_{p_b}^{p}\left(\frac{k_{ro}}{\mu_o z_o} + \frac{k_{rg}}{\mu_g z_g}\right)p'\,dp'$$

and the saturation, which controls both k_{ro} and k_{rg} at each pressure level was obtained from:

$$\frac{k_{ro}}{k_{rg}} = \frac{L\rho_g\mu_o}{V\rho_o\mu_g}$$

A program was written by one of the authors to generate a normalised pseudopressure ($\Psi_{(p)}$ psi) function by quadrature from relative permeability Flash table data sets.

The flash tables were generated by simulating a Constant Composition Experiment (CCE) based on the fluid compositions utilized in each of the simulation models.

The pseudo pressure results were calculated at a close spacing below the dew point to minimize any distortion of the derivative pressure response. They can be imported directly into PanSystem, which performs the two-phase pseudopressure analysis (**Figure 5** shows the base case).

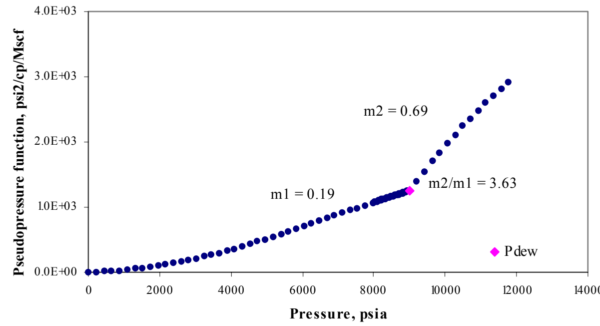


Figure 5: Two-Phase Pseudopressure Plot for Santa Barbara Fluid.

The ratio between the slopes in the single-phase region (above the dew point pressure) and the two-phase region (below the dew point pressure in figure 5) represents the mobility ratio between the outer and inner zones. It would be expected that this is a straight line with unit slope in the single-phase region, as was observed for two further high-pressure condensate fields (**Figure 6**). However, in the case of Santa Barbara Fluid, which has a very high initial reservoir pressure of 11900 psi, the vapour viscosity values above the dew point show a different tendency with pressure -see **Figure 7**. Here, instead of a straight line above the dew point a curve line with a flat tendency was observed with a slope of approximately 0.69 (**Figure 5**).

The low slope value (0.19) of the two-phase region in the base case model indicates the severity of the liquid blocking effect. This is due to the chosen Santa Barbara relative permeability curve.

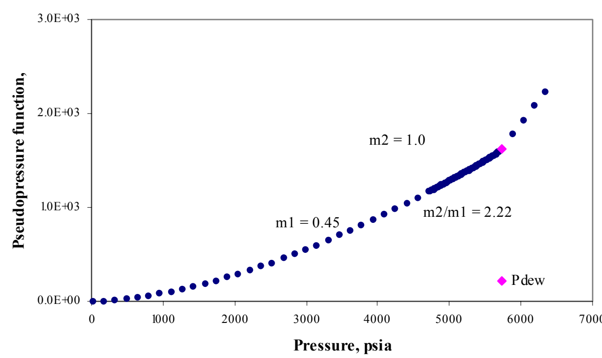


Figure 6: Two-Phase Pseudopressure Plot for a second, high pressure, gas-condensate field.

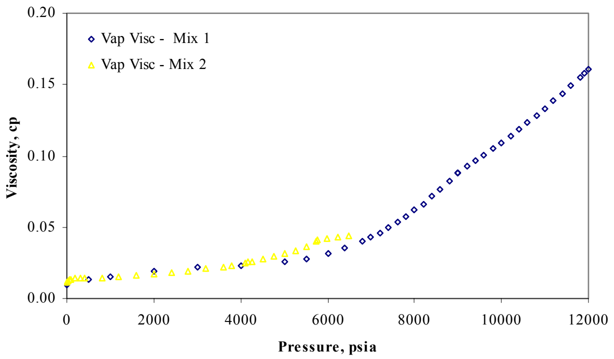


Figure 7: Vapour Viscosities for the Mixtures.

The two-phase pseudopressure function incorporates the effect of relative permeability curves and fluid properties with distance, {Raghavan (1995)}. However, the steady state pseudopressure method ignores the presence of Region 2 (where oil saturation is building up and where only gas is flowing. It assumes that both phases are mobile when the two phases are in equilibrium).

Figure 8, is a log-log plot of the build-up response for the base case 3, showing the derivative curve in terms of the two-phase analogue. In this case, as in most of the simulated cases during this study, the derivative is not a straight line as would be expected from Raghavans (1999) results. Instead, a zero line slope in the middle time region is followed by a concave curve in the transition zone (where oil saturation is building up) and second zero slope line in the early time region is observed. The main reason for the difference in the results is the choice of relative permeability curves. The Raghavan (1999) curves keep k_{rg} equal to unity until the oil becomes mobile for saturations greater than critical oil saturation. By contrast, the relative permeability curves used in this work result in k_{rg} falling below unity as soon as oil drops out from the gas phase.

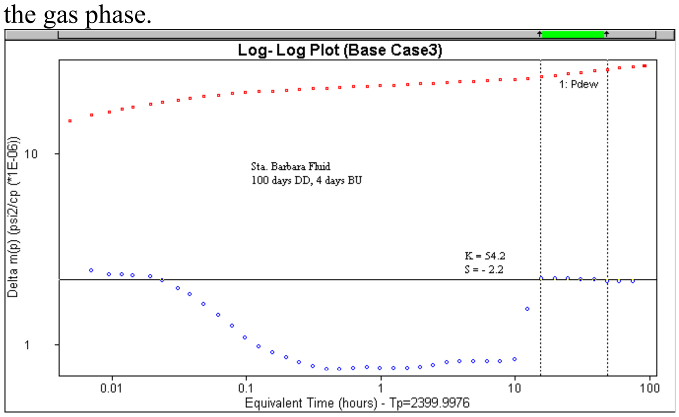


Figure 8: Log-Log Plot. Base Case 3. Two-phase Analysis.

This demonstrates one limitation of the steady-state method. **Figure 9**, does not accurately predict the oil saturation values in the region 2 (where oil is condensing from the gas and is accumulating until it reaches the critical oil saturation).

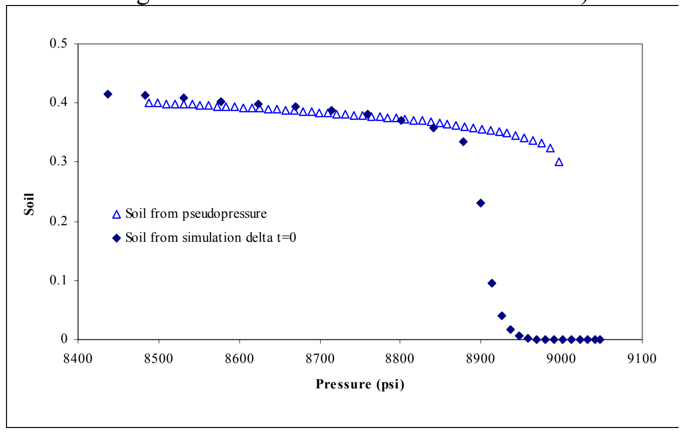


Figure 9: Comparison Plot of Oil Saturation Profile from Steady State Method and Simulation predictions.

Applying the line fitting method in the two-phase analysis log-log plot, a zero slope line can be fitted to the derivative data points in the middle time regionThis allows the relative gas permeability value at the connate water saturation and the mechanical skin factor to be obtained provided that the pseudopressure function has been accurately estimated.

The skin factor estimated by the two-phase analogue would have an error upto two units (which means that the maximum error in the calculated skin value will be -2). This over correction will depend on the real mechanical skin value (see the summary table A-4). Simulations varying the mechanical skin from negative values (wells with fractures) to positive values (wells with formation damage) were performed and a correlation between the skin values obtained from the two-phase pseudopressure analysis and the mechanical skin was derived.

The skin factor estimated with the single-phase analogue may contain contributions from the mechanical skin as well as the liquid drop-out effects. Therefore, a very close approximation of the skin value due to the liquid drop-out effect can be obtained by taking the difference between the two estimates and applying the skin correction using the above correlation. This will help reservoir engineers to discriminate between mechanical skin and liquid drop-out skin and will allow the correct decisions about the required remedial well treatments (stimulations, hydraulic fractures, etc) necessary to optimise the well production.

Compositional Simulation

Compositional simulation models are needed to model reservoir production processes such as depletion of volatile oil and gas condensate reservoirs, miscible flooding and gas cycling. Such simulation models assume that reservoir fluid properties are dependent not only upon the reservoir temperature and pressure but also on the changing composition of the reservoir fluid during production.

In gas condensate reservoirs the impact of relative permeability changes and non-Darcy flow effect varies significantly over relatively small distances. Furthermore, complex phase behaviour effects such as condensation and revapourization in the near wellbore region, require the use of a properly tuned EOS. Hence, accurate simulation of near wellbore phenomena necessitates the use of compositional simulation models with a very fine grid definition near the production well.

The first model that considered the flow of individual components and accounted for component mass transfer between phases was developed Roebuck et al. (1968). They used one of these models to predict the performance of a producing well in a reservoir containing a rich gas condensate. Fussell (1973) modified the one dimensional (1D) radial model developed by Roebuck et al. (1968) and used it to study long term gas, condensate well performance producing by depletion below the dew point pressure. He showed that the productivity predicted by the O'Dell Miller theory (1967) overpredicts the deliverability loss due to condensate blockage, compared with simulation results.

In the present study, a one-dimensional (1D), three phase, radial compositional model was constructed using the commercial simulator Eclipse E300 to evaluate the well test response of a producing well in a gas condensate reservoir in where the pressure is depleted below the dew-point pressure. The simulation work studied only a portion of the reservoir near wellbore. The well is assumed to produced at a constant rate and it is completed throughout the whole interval.

This study assumed the reservoir to be a homogeneous porous media of uniform thickness, where gravity and capillary pressure effects are negligible. Therefore the porosity and permeability data for each of the grid block is assumed to be the same, with values of 8.5% and 50 md respectively.

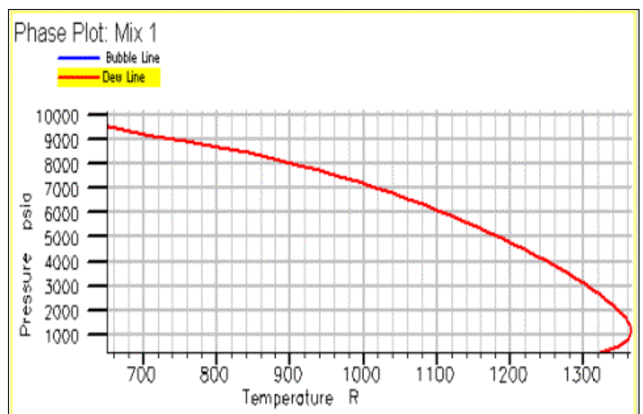
The original pressure of Santa Barbara Reservoir was 11900 psi. However in order to save computational time a pressure of 9100 psi (104 psi above P_{dew}) was used as initial reservoir pressure in the cases where the Santa Barbara fluid was used. The simulation basically consisted of reproducing a well test in which the well is flowed for a considerable period of time (Draw-down) and then closed during 4 days for a pressure restoration period (Build-Up).

PVT Modelling. Original compositions from two different condensate reservoirs were chosen as the condensate mixture to be used in the simulation model. These compositions made it possible to incorporate all the features associated with the phase behaviour relevant to our problem (well productivity, deliverability, prediction, well test analysis).

The phase equilibrium calculations performed in this study use the Modified Peng-Robison EOS. Constant composition experiments (CCE) and constant volume depletion experiments (CVD) were simulated using an adjusted EOS in order to generate the required fluid properties to apply the pseudopressure function. Viscosities of the fluids were calculated with the procedure outlined by Lorhenz et al (1964).

Mix 1 is the Santa Barbara reservoir fluid. This reservoir has a very complex fluid column. A full detailed study of PVT samples, together with an evaluation of the area fluid distribution to define a EOS, was performed by Santa Barbara reservoir group in PDVSA. The final selected EOS was the modified Peng Robinson equation, with 9 pseudo-components, 6 of which were heavy fractions. The vertical location of the modelled well in this study corresponds to the condensate fluid. The dew point pressure of this fluid is 8996 psia. The maximum condensate volume during the CCE is approximately 27.09 %. This fluid composition was used as the base case in this study.

Mix 2 represents the properties of a second condensate reservoir. It is located in the North Sea. The fluid properties were generated using a 6-component system Peng Robinson EOS. The dew point pressure was adjusted using one PVT experiment to the value of 5734 psia, which is much lower than dew point pressure of Mix 1. The maximum condensate volume percentage reached in this case is 20.36 %. **Figure 10**, shows the P-T phase diagrams for both fluids.



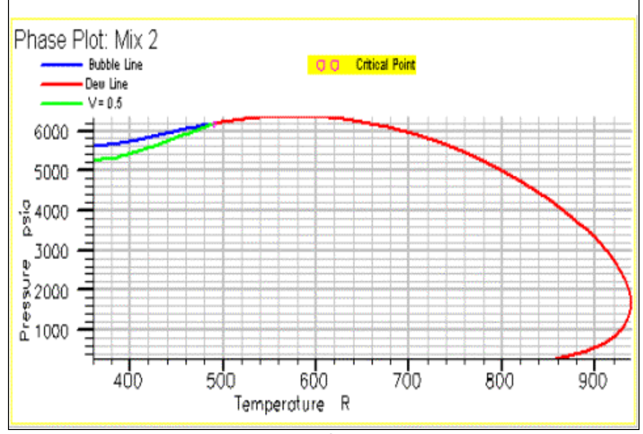


Figure 10: P-T Phase diagrams from Mixture 1 and Mixture 2.

Relative Permeability Model. A key parameter to determine the well deliverability loss is the relative permeability data, therefore it is very important that the experiments used to measure that data consider the process that occurs in these reservoirs.

Conventional gas-oil drainage relative permeability data using steady state or unsteady state flow laboratory experiments have usually been conducted to measure gas relative permeability in the presence of oil condensate. The core is initially 100 percent liquid saturated and the relative permeability measurements are made under the conditions of decreasing liquid saturation. In a gas condensate system the opposite occurs. The reservoir fluid is initially a single-phase vapour above its dew point pressure and the liquid condenses, increasing the liquid saturation (imbibition). The typical drainage relative permeability data do not apply to this situation.

Danesh et al. (1994) described how condensate and gas relative permeability will increase with increasing velocity when measuring relative permeability using condensing fluids in long cores. This new phenomenon was called the "positive coupling effect". These results pointed out the need to use an appropriate experimental technique where the distributions of the phases were representative of those in gas condensate reservoirs when performing experiments as part of a programme to develop relative permeability correlations. The gas condensate core test reported by Danesh et al. were performed by using a high pressure core facility that allowed steady-state relative permeability tests to be conducted.

In the reservoir, gravity and capillary forces will mainly control the condensate mobility. However, when the vicinity of the well is approached, the viscous and capillary forces will dominate the flow. It is within this regime that relative permeability will be most affected by fluid velocity. This is contrary to the conventional non-Darcy flow where the permeability reduces with increasing velocity in inertial flow. Danesh et al. core tests were modelled on the near-wellbore flow regime, where viscous and capillary forces were dominant and gravitational forces where minimized by continually rotating the core.

In this study, a compositional simulation model will be used to evaluate the effect of fluid velocity on the well productivity loss and condensate banking extension based on the correlation between relative permeability and the capillary number identified by Danesh et al. in their work.

The imbibition relative permeability curves from Santa Barbara condensate reservoir have been used in this study as a base case to perform all the sensitivity cases. These curves were taken from the Santa Barbara full field simulation model, and were manually scaled using the same endpoints as the one established in the Santa Barbara input data file.

The reason to carry out the scaling process, instead of using the normalized set of relative permeability curves in the radial compositional model, was to be certain that the relative permeability curves used in the well model to generate the pseudopressure function were the same set of relative permeability curves employed in the simulation model. The critical condensate saturation fraction in the gas oil system in Santa Barbara relative permeability curves is 0.3, the connate water saturation fraction is 0.23. The critical gas saturation is 0.02. **Figure 11**, shows the Santa Barbara relative permeability curves.

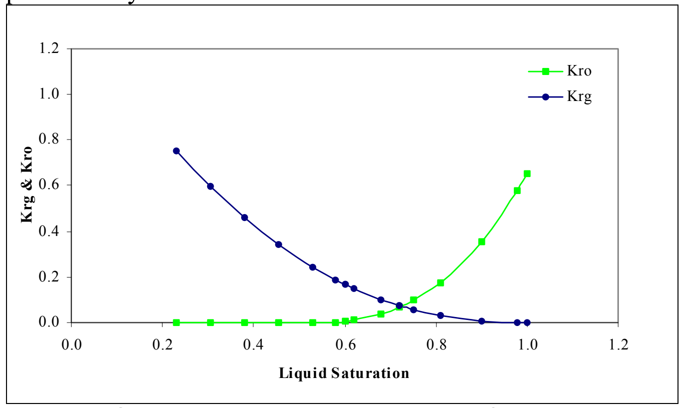


Figure 11: Santa Barbara Relative Permeability Curves

Six additional different relative permeability curves e.g.Figure 12 were used in this study, to investigate their effect on the extent of the condensate bank formed near to wellbore region in a condensate reservoir once the bottomhole flowing pressure goes below the dew point pressure.

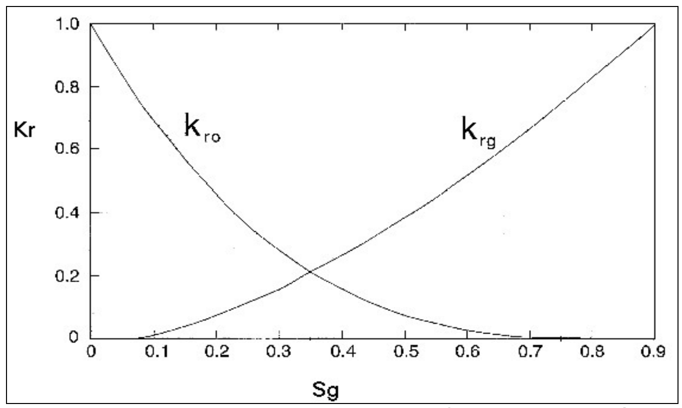


Figure 12: Relative permeability curves from a second South American Field

The Figure 12 relative permeability curves were chosen because they have already been tuned to well test data and were considered representative for liquid dropout phenomena. These curves are shown in **Figure 12**. The critical condensate saturation is 0.15 and the connate water saturation is 0.1, and the trapped gas saturation is 0.075. As expected, the relative permeability to oil is negligibly small until the liquid saturation becomes quite large.

Model Optimisation and Verification

The first objective in this work was to choose the most appropriated type of model and select the optimum grid sizeso as to obtain the most accurate results A compositional simulation was used to reproduced the well test response in a gas condensate well. Numerical errors can be introduced in the simulation by spatial and temporal discretisation. A sensitivity study of the grid size and time steps was carried out with the aim of avoiding these numerical truncation errors.

In both sensitivities, the grid size and time stepping of the single-phase simulation was performed keeping the reservoir pressure above the dew point. The well test pressure responses obtained from the simulations were analysed. The reservoir properties (permeability and skin) calculated using analytical solutions where compared with the input data in the simulation model in order to verify the accuracy of the simulation model.

The final model grid chosen consisted of 26 grid blocks in the radial direction. The size of the cells near to the wellbore was 0.18 ft deep, increasing logarithmically by a factor of 1.5 to grid block 26. One of the important observations noticed during the grid size sensitivity study was that the logarithmic increase of the grid cells had to be made with respect to the wellbore radius. Otherwise the calculated skin value using the analytical solution will differ from the input value in the model.

Fluid Effect Two different fluid systems were considered in order to study the effect of mixture richness on well productivity. Their liquid drop out curves derived from the constant composition expansion CCE are shown in **Figure 13**.

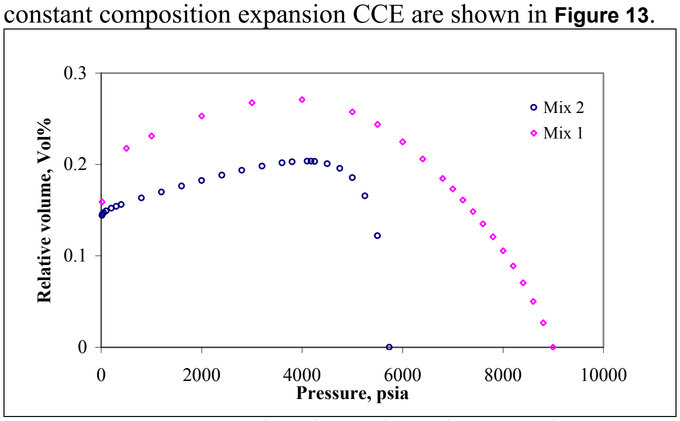


Figure 13: Liquid Drop-Out Curve from Constant Composition Expansion Experiment (CCE).

Six different cases were performed by changing the well production conditions and the fluid properties using the base case (Santa Barbara fluid and reservoir properties). The objective was to evaluate how the condensate bank length varies according with the fluid richness. The initial reservoir pressure was set above the dew point pressure and the initial pressure difference ($P_i - P_{dew}$) was considered to be the same in all the cases and equal to 104 psia.

As expected the oil saturation profiles showed that the richer fluid generated the larger condensate bank. This can be clearly observed in **Figure 14**. The plots on the left column correspond to Mix 1 while the plots on the right column correspond to Mix 2. Mix 1 fluid is richer than Mix 2 (**Figure 13**) and gives a larger condensate bank.

It can also be clearly seen from this figure that the maximum amount of condensate build up near to the wellbore is basically controlled by the critical oil saturation value. The condensate saturations in the region of the producing well are much greater than those measured experimentally during the CVD or CCE.

Effect of Skin. The mechanical skin values estimated in well test analysis using the two-phase pseudopressure function contain an over-correction error that can reach a maximum value of two units when the real mechanical skin factor is zero. A number of cases with varying mechanical skin values - ranging from negative (stimulated wells) to positive values (wells with formation damage) - were simulated in order to evaluate the effect of mechanical skin on the reliability of the steady-state, pseudopressure calculations. The skin was modeled with the Hawkins equation by introducing a near wellbore zone of altered permeability (k_a) and radial depth r_a:

$$S = \left(\frac{k}{k_a} - 1\right) Ln \frac{r_a}{r_w}$$

The results obtained from the skin sensitivity are shown in **Figure 15**, where the skin calculated by using the two-phase pseudopressure analysis and the mechanical skin value input in the simulator are plotted. A good correlation for estimating the mechanical skin using the two-phase pseudopressure analysis was found:

$$S_{ps} = -1.95 + 1.123 * S_m$$

where S_{ps} is the mechanical skin estimated with the two-phase pseudopressure analysis and S_m is the real mechanical skin.

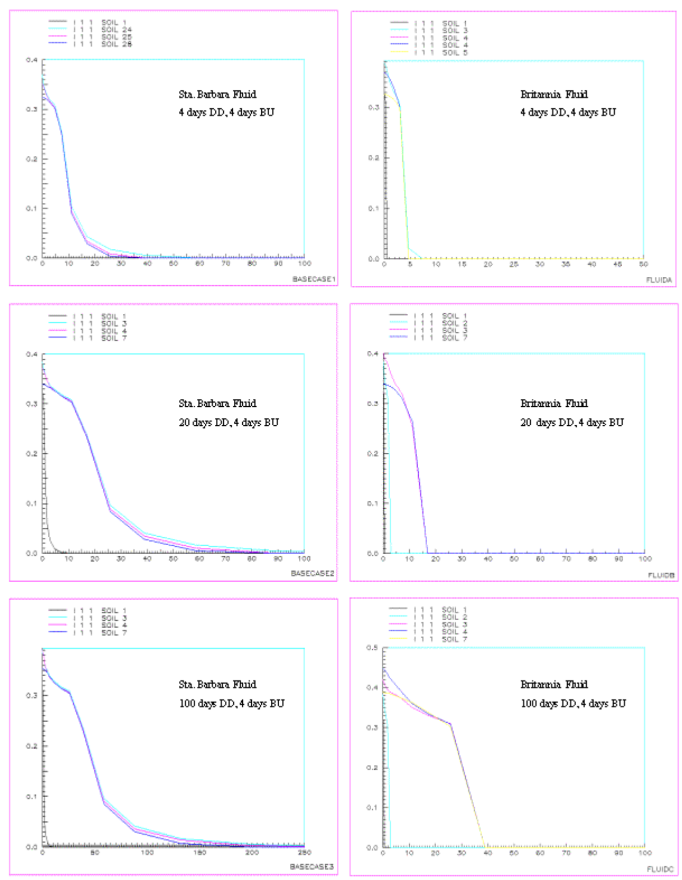


Figure 14: Oil Saturations Profiles for both fluids Mix 1 and Mix 2.

From **Figure 16**, it can be concluded that large total skin values (estimated with single-phase analysis pressure) indicate a positive mechanical skin is present. The error in the skin estimated from the pseudopressure analysis will decrease as this mechanical skin value increases. However, if the mechanical skin estimated using two-phase pseudopressure is between 0 and –2.2, the mechanical skin is small or may be equal to zero. The mechanical skin has negative value if the skin from the two-phase analogue is smaller than approximately –2.2.

The flow capacity estimated using the two-phase pseudopressure analysis was accurate in all cases studied, the kh values being identical and independent of the skin value.

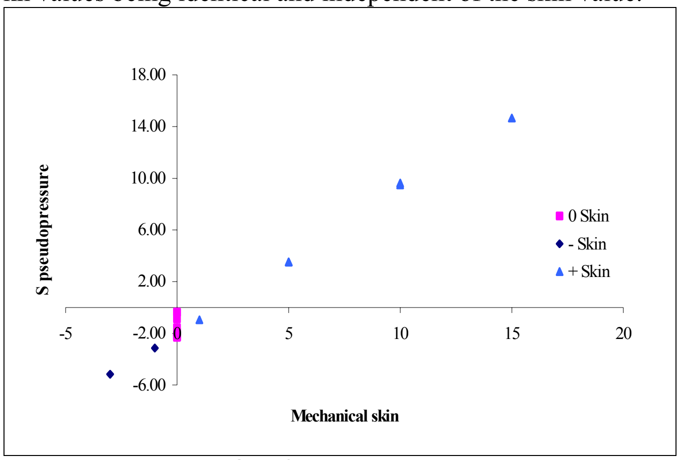


Figure 15: Mechanical Skin from the Pseudopressure Analysis vs. Real Mechanical Skin

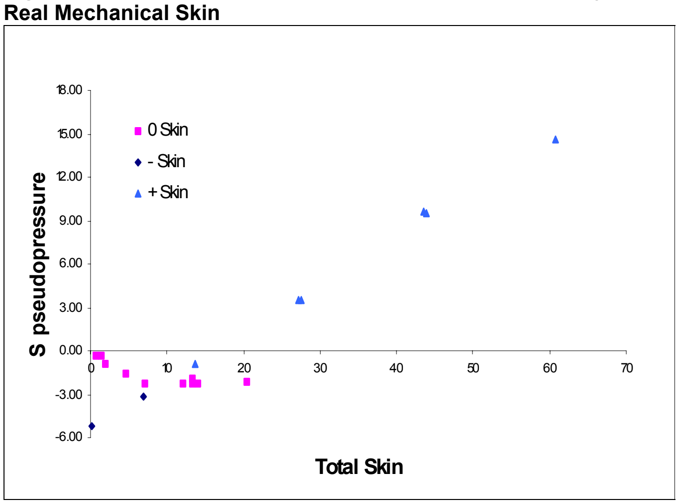


Figure 16: Mechanical Skin from the Pseudopressure Analysis vs. Total Skin

Saturation Changes. The part of the study aims to predict how the oil saturation profile behaves with time. A plot of oil saturation versus radial distance away from the wellbore at different times was made for the base case. In this particular case the well was flowed at a constant rate of 14 MMscf/d during 100 days and shut-in for 4 days.

It can be noticed that the oil saturation profile is smooth until the critical oil saturation value is reached. The shape of the curve radically changes at this point since a portion of the condensate drop-out is being produced (**Figure 17**). Some revaporization of the liquid takes place during the build up phase for radial distances near to the two-phase zone (r >30ft) i.e. the condensate bank length slightly decreases with time during the build-up period. This was observed by Jones and Raghavan, (1987).

In order to estimate the condensate bank size at different times during the simulated well test, a curve fit program was utilized to find the model function that represented the data in the most accurate way.

The integration of the adjusted model function will give as a result the total area below the oil saturation curve. Thus, the average condensate length value at a specific time step will be equal to the length value that makes the integral approximately half of the total area. Using this methodology and comparing the oil saturation profiles during the build-up and draw-down periods, a small variation in the size of the two-phase zone was found. Following a 100 hour draw-down, a condensate bank length of 31 feet was initially formed which decreased to 29 feet after the four hours build-up period.

In addition, the build-up pressure response analysis gave a result of approximately equal to condensate bank length (L_{rad} =35 feet) for the same case (Base Case 3). This indicates that the condensate length value obtained with a well test pressure analysis is representative of the length at an averaged oil saturation value. It is not equal to the total extension length of the condensate bank, 360 ft in this case (**Figure 4**).

Different cases were run in order to evaluate the extension of the condensate bank as a function of the total production time. This showed how compositional simulation can be used as a design tool in gas condensate well testing in order to estimate the required flowing time (or draw-drown) period prior to the build-up period in order to ensure that condensate bank formation is observable in the well test derivative pressure response using the Radial Composite Model

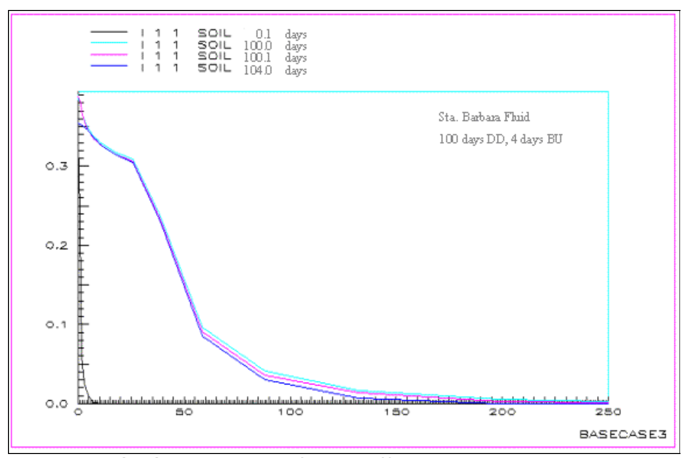


Figure 17: Oil Saturation Profile at different time steps

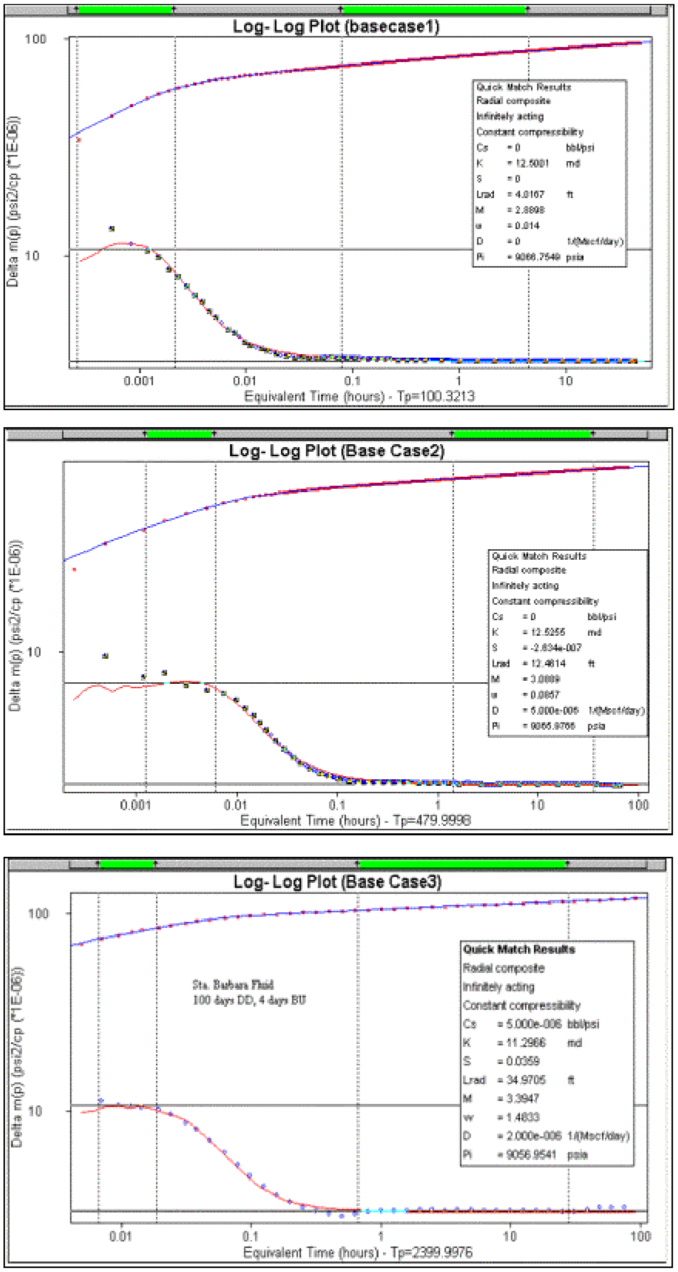


Figure 18:Log-Log Plots of 3 Different simulation Cases Comparing the Condensate Bank Length varying the draw-down period.

Velocity effect. Professors Danesh and Terhani at the Institute of Petroleum at Heriot Watt University are developing generalized correlations for relative permeability, fluid velocity and fluid properties (IFT, density, etc) suitable for use when describing condensate flow. One such correlation relates the relative permeability to the capillary number (Nc). This correlation has been included in the commercial software Eclipse 300 through the use of a keyword called VELDEP. It allows the user to introduce into the model the result of combining the Interfacial Tension (IFT), and velocity through the so-called Capillary Number.

In the present work a sensitivity study was performed in order to evaluate the effect of Capillary Number on the well deliverability. Several cases were run including this keyword and results were compared with the cases where no velocity dependent relationship was included.

There are various alternatives to calculate the capillary number. We used:

$$N_c = \frac{\upsilon_g \mu_g}{\sigma}$$

i.e., the capillary pressure is proportional to the gas velocity and inversely proportional to the IFT

The capillary model has two effects on the gas and oil relative permeability curves. As the Capillary Number increases it first reduces the residual saturations and, secondly, changes the relative permeability from the user-specified (immiscible) saturation curves to an internally generated miscible saturation curve. The influence of the capillary number, Nc is certainly not negligible in gas/condensate flow.

Six cases with varying the flowing time period and including the velocity relative permeability effect were simulated. Fluid and reservoir properties were kept the same and equal to the fluid and reservoir properties of the Santa Barbara reservoir. **Figure 19**, shows the pressure derivative response for cases where the velocity dependent relative permeability was NOT used (right-hand column) and cases where this effect WAS included (left-hand column). It can be clearly seen, that the reservoir model changes from radial composite model to an almost homogeneous reservoir where the condensate bank has not been formed or the effect of the mobility changes is so small that it is not being reflected in the pressure derivative.

The results obtained in this section may provide a plausible explanation of why, in many well tests of real gas condensate wells in which the bottom hole pressure goes below the dew point, it is not possible to observe a radial composite behaviour in the derivative pressure response.

Low Permeability Effect. Deliverability loss in gas condensate fields producing below the dew-point pressure is particularly acute in the case of low-permeability reservoirs. A case where the reservoir permeability value was reduced to 5 md was run with the objective of evaluating how this parameter would affect the well productivity and the length of the condensate bank.

As in the Base Case 3, the well was produced for a period of 100 days at a constant rate value of 14 MMscf/d, followed by a build-up period of 4 days. A very low, flowing bottomhole pressure (1789 psi) compared with the initial reservoir pressure value (9100 psi) was observed due to the low permeability value.

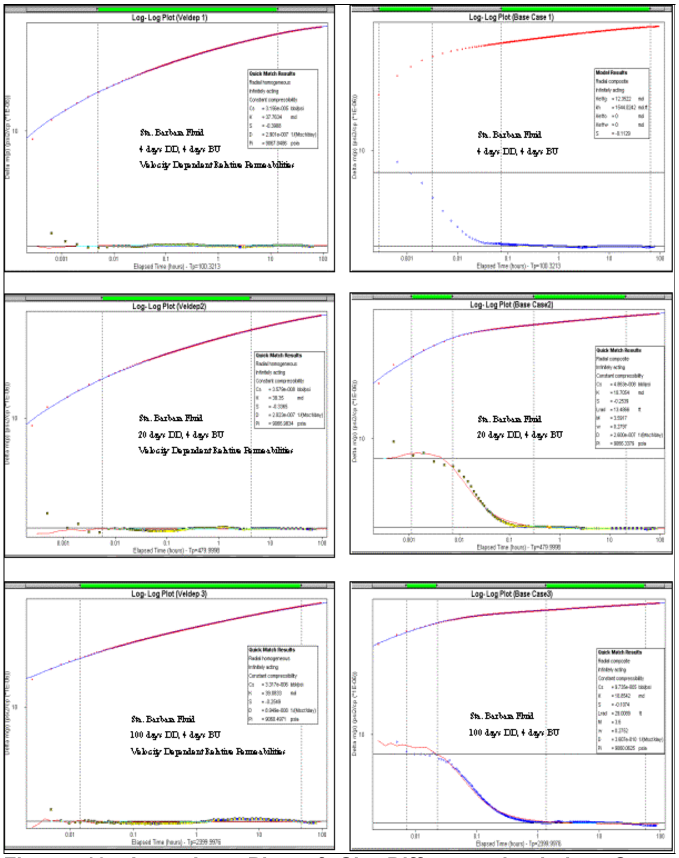


Figure 19: Log- Log Plot of Six Different simulation Cases Comparing the Effect of Using Velocity Dependent Relative Permeability.

The oil saturation profile was plotted at different time steps. The oil saturation values in the grid blocks around the wellbore reached values greater thn the oil critical saturation (S_{ocr} = 0.3) during the draw-down period. This is due to the high-pressure drops near to the wellbore. It implies more oil has condensed than the oil volume actually produced (**Figure 21**).

In addition, it was also noticed that, during the build-up period, once the well was closed the oil saturations around the well increased up to a value of 0.77 (S_{oil}=1 – S_{wc}) i.e. no gas saturation was present in these blocks. This oil saturation behaviour was opposite to the one observed in the previous cases studied (the oil saturation near to the wellbore hardly changed after the well was closed-in). A good explanation for this behaviour can be found in the plot of block pressure vs. radial distance for the last four time steps during the build-up period. It was observed that even though the block pressure in the blocks away from the wellbore were above the dew point pressure, the pressure in the near wellbore area was still below the dew point even at the last time step 4 days after the build-up started (**Figure 20**).

This total gas blocking effect behaviour in low-permeability reservoirs implies that a much greater than expected drawdown pressure will be required to return the well to production.

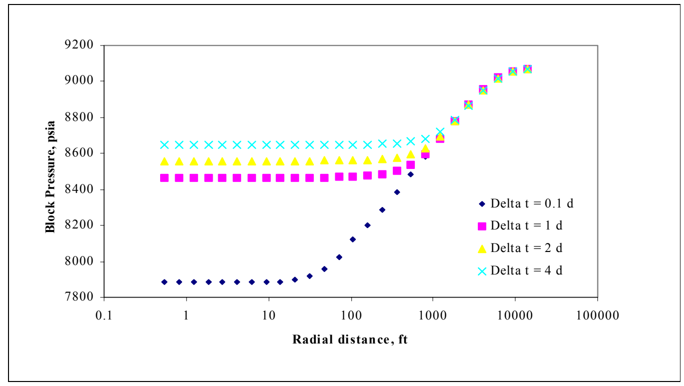


Figure 20: Block Pressure vs. Radial Distance during the Build-Up period. k= 5md

These observations highlight the importance of using compositional simulation in tight gas condensate reservoirs, where dramatic compositional changes are present around the wellbore, in order to be able to predict the well productivity impairment of condensate wells producing below the dew point pressure.

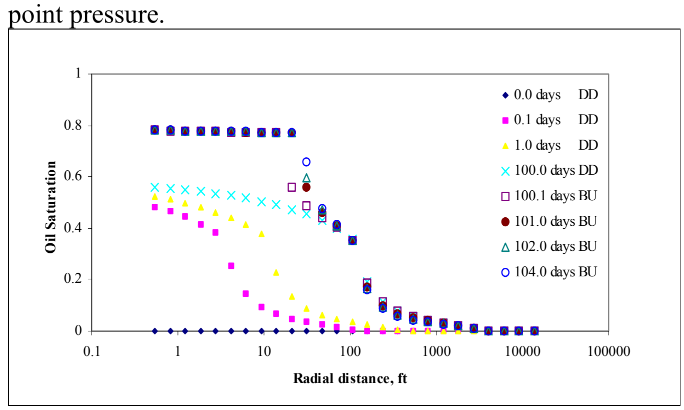


Figure 21: Block Oil Saturation vs. Radial Distance. k= 5md

Relative Permeability Effects. Different sets of relative permeability curves were used to investigate the effect of relative permeability characteristics on the magnitude of the condensate bank produced due to the liquid drop out once the pressure drops below the dew point.

Set 1: Santa Barbara relative permeability curves.
Set 2: S. America Field Two relative permeability curves.
Set 3: Corey expression no S_{ocr}, m'= 2.5 and n' = 2.2.
Set 4: Corey expression no S_{ocr}, m'= 4.0 and n' = 2.2.
Set 5: Corey expression no S_{ocr}, m'= 7.0 and n' = 2.2.
Set 6: Corey expression no S_{ocr}, m'= 9.0 and n' = 2.2.

The relationship between k_{rg} vs k_{rg}/k_{ro} is important to determine the deliverability loss due to condensate blocking.

In the two-phase pseudopressure expression only the gas term plays an important part.

$$m_{D(tD)} = \frac{2\pi k h C_1}{q_t} \int_{P_i}^{P_{wfs}} \left(\rho_o \frac{k_{ro}}{\mu_o} + \rho_g \frac{k_{rg}}{\mu_g} \right) dp'$$

Using Corey's Method (1954), a simple mathematical expression for generating different sets of relative permeability was applied. See equations below:

$$k_{ro} = \left(k_{ro}\right)_{S_{gc}} \left[\frac{1 - S_g - S_{lc}}{1 - S_{gc} - S_{lc}}\right]^{m'} \quad , \quad k_{rg} = \left(k_{rg}\right)_{S_{wc}} \left[\frac{S_g - S_{gc}}{1 - S_{gc} - S_{lc}}\right]^{n'}$$

where n' and m' are exponents on relative permeability curves.

The different permeability curves including the base case are shown in the **Figure 22**. Each of the simulated cases were analysed using the approach explained before. As expected, the condensate bank length obtained from the pressure analysis results increased as the value of m' was increased. This is equivalent to saying the blocking effect in the two-region phase has increased. Furthermore, it was observed that the error in the skin obtained from two-phase pseudopressure analysis was kept within 2 units as was concluded above.

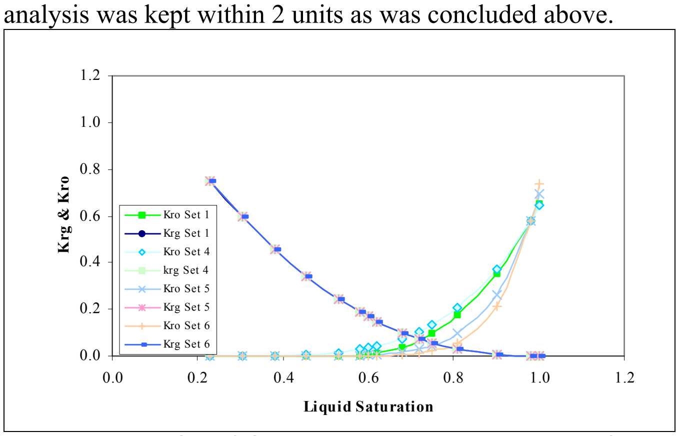


Figure 22: Four Set of Gas- Liquid Relative Permeability Curves that have Different m' value.

Critical Oil saturation effect. A last case varying the relative permeability curves in the simulation model was carried out in order to evaluate how sensitive the two-phase pseudopressure method was to this parameter. This set of relative permeability curves was also generated using Corey's expressions but on this occasion, a critical oil saturation value of zero was used (no S_{ocr}).

Comparing the results in this case (no S_{ocr}) with those from the Base Case 3, it was observed that the error in the mechanical skin estimated with the two-phase pseudopressure analysis was reduced from a value of –2.2 in the Base Case 3 to a value of – 0.9 in the case of no critical oil saturation being present (Table A-4).

Saturated Reservoir (P_r < P_{dew}) It would be advantageous for a gas condensate reservoir to be produced at a reservoir pressure above the dew point pressure for as long as possible. E.g. by implementing a pressure maintenance project or by performing hydraulic fracture treatments to reduce the pressure drop near to the wellbore. However, this is not always possible and some condensate reservoirs will be depleted to an average reservoir pressures below the dew point. This has been modeled in this section - the reservoir pressure at the beginning of the well test is below the dew point pressure, (P = 7100 psi). The well was flowed during 100 days and shut in for a build up period of 10 days.

This well test was analysed first using the single-phase analogue. Results of the single-phase analysis are shown in **Figure 26**. It was observed in the pressure derivative log-log plot that, even though the whole reservoir was below the dew point pressure, a radial composite model was observed as a consequence of mobility changes due to the variation of oil saturations with pressure. Figures 24 and 23 plot the block pressure and oil saturation against radial distance, respectively. Furthermore, in the single-phase analysis log-log plot, it can be observed that the outer zone permeability estimated using single-phase pseudopressures is a reduced permeability value due to the presence of oil in that region. In this particular case the permeability of the outer zone was equal to 26 md. From this value the relative permeability to gas (k_{rg} = k_{eff}/k_{abs}) was calculated (0.52). Using the relative permeability curves in the simulation model, it was found that the oil saturation at this k_{rg} value was similar to the averaged oil saturation value (0.12) away from the wellbore (**Figure 25**). It was also noticed that the inner zone skin value, was equal to zero reflecting the real mechanical skin (0) used as input value into the model.

The condensate bank length estimated in this single-phase analysis is very close to the length at which the simulation predicts both phases will become significantly mobile.

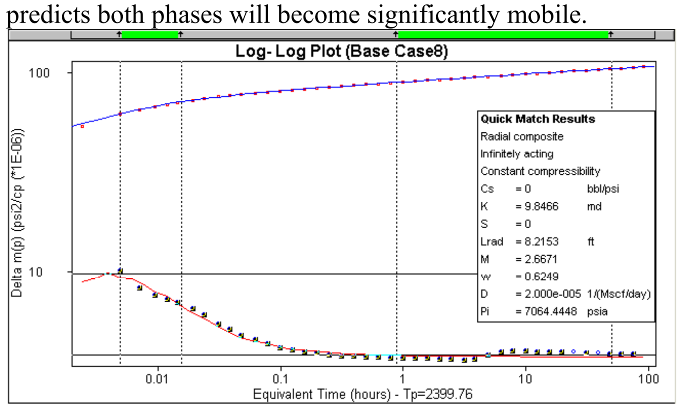


Figure 23: Log-Log Plot. Single-Phase Pseudopressure Analysis. (P_i < P_{dew}).

A two-phase pseudopressure function was also generated with the aim of investigating the applicability of the two-phase pseudopressure method in gas condensate reservoir when the initial reservoir pressure is below the dew point. Fluid properties to be used in the flash PVT table were generated by simulating a Constant Composition Expansion experiment (CCE) of the produced fluid composition.

Results of this two-phase flow analysis are shown in **Figure 26**. It can be seen from this plot that the shape of the derivative after applying the two-phase pseudopressure function is exactly the same as in the case of single-phase analysis. This is due to the pressure response data being below the dew point. The permeability value estimated with this analysis was not the absolute permeability and the skin effect was not equivalent to the mechanical skin value input in the simulation model {as achieved in the previous cases (P_i > P_{dew})}. These outcomes show the limitation of the two-phase pseudopressure method in the case of initial or average reservoir pressure below the dew point. This was also noted by Raghavan et al.

(1999).**Figure 27**, clearly shows that oil saturations computed from the steady-state pseudopressure method deviate from the simulation data at the transition zone (two-phase present but just gas is flowing) where much higher oil saturation values are predicted.

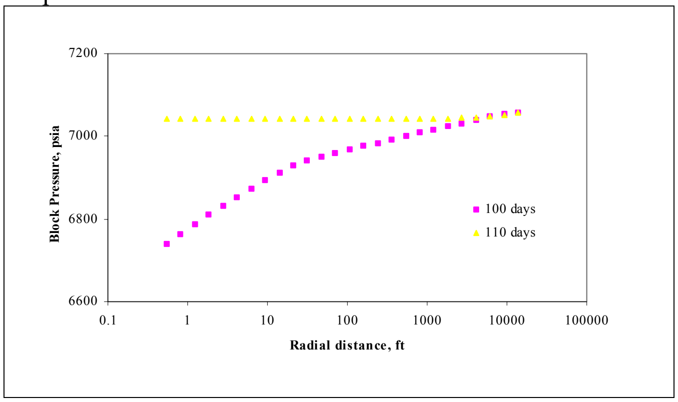


Figure 24: Block Pressure vs. Radial Distance. ($P_i < P_{dew}$)

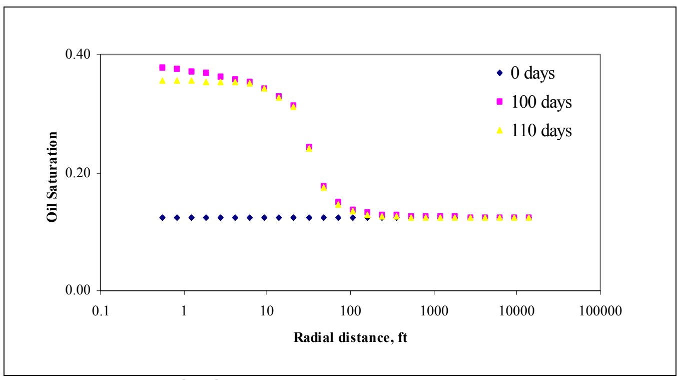


Figure 25: Block Oil Saturation vs. Radial Distance ($P_i < P_{dew}$)

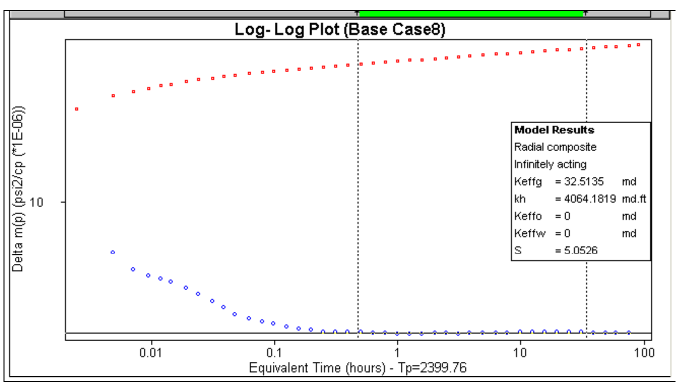


Figure 26: Log-Log Plot. Two-Phase Pseudopressure Analysis. ($P_i < P_{dew}$).

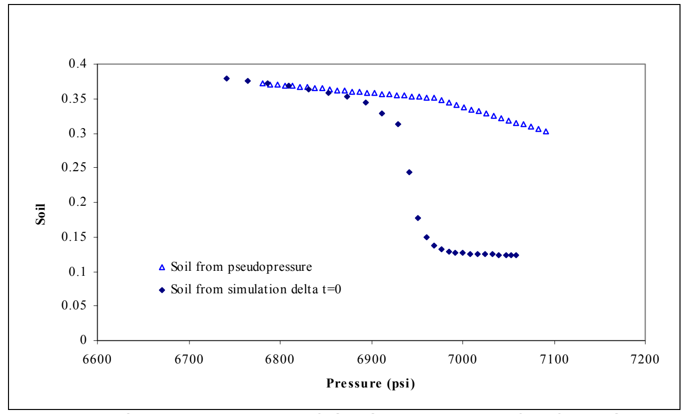


Figure 27: Comparison Plot of Oil Saturation Profile from Steady State Method and Simulation predictions ($P_i < P_{dew}$).

Comparison of Vertical and Horizontal Wells.

Horizontal oil wells are frequently more productive than vertical wells. We have used a radial compositional simulation model to compare the well performance of vertical and horizontal wells in a gas condensate reservoir.

Several simulations were run using the same, constant, surface production rate of (14 MMscf/d), but with a varying drain hole length (831 m, 559 m, 369 m). It as expected, the pressure drop during the drawdown in a horizontal well is much smaller than that for a vertical well (**Figure 28**). This means that problems associated with liquid drop out accumulation near to the wellbore can be reduced by using horizontal wells.

The well was produced for 100 days. It was observed that, due to the small drawdown pressure in the horizontal well case, t an increase in the oil saturation was not observed. **Figure 29** is the log-log plot of the pressure and pressure derivative response in this horizontal case. A radial composite model is not observed, instead a hemiradial flow in the middle time region and a linear flow at late time region are seen. This is normal for horizontal well behaviour during well test analysis. In the corresponding vertical well case, a condensate bank was built up during the same period of time. (**Figure 4** shows the log-log plot of the pressure and pressure derivative response for Base Case 3.

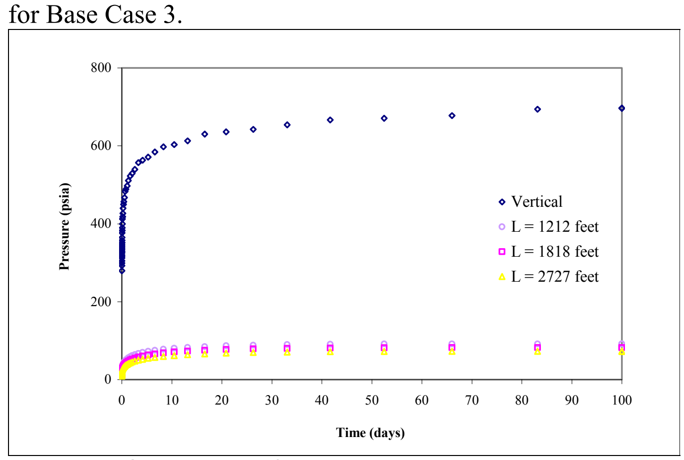


Figure 28: Comparison of Pressure drawdown between Vertical and Horizontal Well

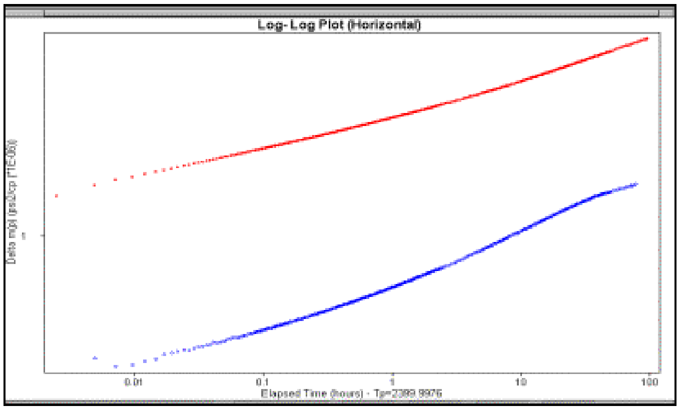


Figure 29: Log- Log Plot pressure and pressure derivative response in the horizontal Well

Conclusions and Recommendations

In this study a 1D radial compositional simulation model has been used to simulate a gas condensate well test response under multiphase conditions. A range of sensitivity studies was carried out to illustrate the most important features occurring in a gas condensate reservoir under depletion conditions.

Based on the analysis and interpretation of each of the simulated cases, a methodology using steady-state two-phase pseudopressure function has been established in order to obtain the most realistic results from a gas condensate well test analysis. This methodology assumed the available relative permeability and fluid properties data was correct.

We concluded that:

1. If a condensate bank has been formed in the area near to the wellbore when the bottom-hole pressure is less than the dew point pressure, a radial composite model will be observed in the pressure derivative when using single-phase pseudopressure analysis.

2. If the reservoir pressure is above the dew point pressure, formation transmissibility (kh), reservoir pressure and total skin factor can be accurately estimated by using a single-phase pseudopressure analogue.

3. The length of the condensate bank estimated with this single-phase analysis has been shown to be the length corresponding to an averaged oil saturation value and not equal to the total extension of length of the condensate bank.

4. The two-phase pseudopressure function, which incorporates the influence of changes in relative permeability and fluid properties, may be used to estimate both absolute permeability and mechanical skin factor. The latter has an error of - 2 units.

5. A correlation has been derived to estimate the mechanical skin effect from the pseudopressure skin value for the cases where the mechanical skin was different to zero.

6. A two-phase pseudopressure analysis cannot be applied if there is not indication of radial composite effect in the pressure derivative response.

7. The length of the condensate bank depends on the composition of the reservoir fluid. It was found that a richer fluid generates a longer the condensate bank and a greater skin effect.

8. The revaporization effect during the build-up period was demonstrated to be minimal in the cases studied.

9. Velocity dependent relative permeability effect can minimize, or prevent in some cases, the accumulation of condensate in the area near to the wellbore. This case will then show homogeneous reservoir model behaviour in the pressure derivative response.

10. In tight reservoirs a total gas block effect was observed due to oil being the only mobile phase present in the near wellbore area when the well was shut-in. This was attributed to the likely high-pressure drops occurring in the near-wellbore region.

11. If the reservoir pressure is below the dew point pressure, the derivative pressure response will show a radial composite model attributable to the variations of oil saturations with pressure. Single-phase analysis in these reservoirs will give a reduced permeability value as a result of the oil saturation presence and the inner zone skin value will reflect the real mechanical skin.

12. The steady-state two-phase pseudopressure method was found not to applicable to the analysis of gas condensate well test when the reservoir pressure is below the dew point pressure. The oil saturation values predicted by this method are much higher than the simulated values.

13. Horizontal wells can minimize the accumulation of condensate in the region of the producing well as a result of the smaller pressure drop values observed during the draw-down period compared with those for vertical well performance.

14. Compositional simulation is an important tool in gas condensate well testing design to estimate how long the flow period should be in order to distinguish a condensate bank formation in the well test derivative pressure response (Radial Composite Model).

Acknowledgments

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Nomenclature

B_{gd}: Dry gas formation volume factor, RB/scf
B_o: Oil formation volume factor, RB/STB
C1: Conversion constant, 0.00633 ft3/ft
h: Reservoir thickness, ft
k: Absolute permeability
k_{rg}: Gas relative permeability
k_{ro}: Oil relative permeability
kh: Flow capacity
L: Liquid molar fraction
m: Slope
$m_{(p)}$: Pseudopressure function
$m_{gas(p)}$: Real gas pseudopressure, psi-lbm/cp ft3
Nc: Capillary Number
p_{dew}: Dew point pressure, psi
p_i: Initial reservoir pressure, psi
p_r: Reservoir pressure, psi
P_{sep}: Separator pressure, psi
p_{ws}: Well shut pressure, psi
p_{wf}: Well flowing pressure, psi
qt: Total flow rate, MSCF/d
r: Radial distance, ft
R: Gas constant, 10.735 psi-ft3/lb-m ºR
Rp: Producing gas oil ratio, MCF/STB
Rs: Solution gas-oil ratio, MCF/STB
r_w: Well radius, ft
S: Skin
St: Total skin
Sm: Mechanical skin
Sps: Mechanical skin estimated with two-phase pseudopressure
Slc Critical liquid saturation
Socr: Critical oil saturation
t: time
T: Reservoir temperature, ºF
tp: Producing time
Tsep: Separator temperature, ºF

Subscripts

o oil phase
g gas phase
m phase indicator

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Apendix A

						Single Phase pseudopressure				Lrad	Two-phase pseudopressure				error	Observation
Cases	Rel_Perm Curve	Fluid	DD (days)	Qg Mscf/d	Sm	Kout, md	Sout	Kinn, md	Sinn	WT	K', md	S'	K, md	S		Pi>Pdew
Basecase1	Set 1	Mix 1	4 days	14000	0	38	5.46	13	0	4	40	-2.1	53	-2.22	-2.22	Pi>Pdew
Basecase2	Set 1	Mix 1	20 days	14000	0	38	7.99	13	0	13	40	-2.1	53	-2.22	-2.22	Pi>Pdew
Basecase3	Set 1	Mix 1	100 days	14000	0	38	12	111	0	35	41	-2.09	54	-2.21	-2.21	Pi>Pdew
Basecase4a	Set 2	Mix 1	100days	14000	0	50	0.79	44	0	24	48	-0.36	48	-0.36	-0.36	Pi>Pdew
Basecase5	Set 3	Mix 1	100 days	14000	0	38	2	26	0	40	36	-0.8	48	-0.90	-0.90	Pi>Pdew
Basecase6	Set 4	Mix 1	100days	14000	0	38	4.6	22	0	14	36	-1.46	48	-1.57	-1.57	Pi>Pdew
Basecase7	Set 1, K= 5md	Mix 1	100 days	14000	0	4	13.4	1	-1.3	176						Pi>Pdew
Basecase8	Set 1	Mix 1	100days	14000	0	15	6.5	7	0	9					Pi<Pdew, Pi = 7100 psi	
Basecase9a	Set 2	Mix 2	100 days	20000	0	49	1.45	39	0	56	47	-0.36	47	-0.36	-0.36	Pi>Pdew
Basecase10	Set 5	Mix 1	100days	14000	0	40	13.4	10	0	17	40	-1.79	53	-1.91	-1.91	Pi>Pdew
Basecase11	Set 6	Mix 1	100 days	14000	0	40	20.4	7	0	18	39	-2.05	53	-2.17	-2.17	Pi>Pdew
Basecase12	Set 1	Mix 1	100 days	20000	0	42	13.3	11	0	31	13	-1.7	55	-2.31	-2.31	Pi>Pdew
Basecase13	Set 1	Mix 1	100 days	25000	0	43	14	11	0	41	13	-1.7	55	-2.31	-2.31	Pi>Pdew
Basecase15	Set 1, K= 5md	Mix 1	100 days	1400	0	4	7.11	1	0	11	4	-2.18	5	-2.30	-2.30	Pi>Pdew
Basecase17aa	Set 1	Mix 1	100 days	14000	5	38	27.6	5	0	17	41	3.64	54	3.51	-1.49	Pi>Pdew
Basecase18aa	Set 1	Mix 1	100 days	14000	10	37	43.9	3	0	12	41	9.6	54	9.48	-0.52	Pi>Pdew
Basecase19aa	Set 1	Mix 1	100 days	14000	15	38	60.7	2	0	11	39	14.78	52	14.65	-0.35	Pi>Pdew
Basecase20aa	Set 1	Mix 1	100 days	14000	-3	38	0.23	73	0	16	41	-5.04	55	-5.16	-2.16	Pi>Pdew
Basecase21aa	Set 1	Mix 1	100 days	14000	-1	38	6.9	15	0	16	40	-3.02	54	-3.14	-2.14	Pi>Pdew
Basecase22aa	Set 1	Mix 1	100 days	14000	1	38	13.6	10	0	27	41	-0.83	54	-0.95	-1.95	Pi>Pdew
Basecase17ab	Set 1	Mix 1	100 days	14000	5	38	27.1	7	0	18	41	3.66	55	3.53	-1.47	Pi>Pdew
Basecase18ab	Set 1	Mix 1	100 days	14000	10	37	43.6	4	0	9	41	9.75	55	9.63	-0.37	Pi>Pdew

Table A-4:Results Summary Table