SPE 62920

Well Test Analysis in Gas-Condensate Reservoirs

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This paper was prepared for presentation at the 2000 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, 1–4 October 2000.

Abstract

Published analyses of well tests in gas-condensate reservoirs when pressure drops below the dew point are usually based on a two-zone radial composite model, representing regions of condensate drop-out around the wellbore and of initial gas composition away from the well. Laboratory experiments, on the other hand, suggest that three different mobility zones could exist: (1) an outer zone away from the well, with the initial liquid condensate saturation; (2) a zone nearer to the well, with increased condensate saturation and lower gas mobility; and (2) a zone in the immediate vicinity of the well with high capillary number which increases the gas relative permeability, resulting in a recovery of much of the gas mobility lost from condensate blockage.

This paper investigates the existence of this latter zone in well test data. An example of well test analysis is discussed, which illustrates the difficulty of identifying such a zone as, in many cases, build-up and/or drawdown data are dominated by wellbore phase redistribution effects. Where the three zones can be identified, data are analyzed using a three-zone radial composite model to yield a complete characterization of the near-wellbore effects, and in particular the knowledge of the various components of the total skin effect: mechanical skin; rate-dependent two-phase skin; and skin due to gas condensate blockage. The existence of the three zones and the results of the analysis are verified with a compositional simulator where relative permeability depends on capillary number.

Introduction

Gas condensate reservoirs exhibit a complex behavior due to the existence of a two-fluid system, reservoir gas and liquid condensate[1-4]. Three main problems are caused by liquid drop-out when wells are produced below the dew point, namely: a non-reversible reduction in well productivity; a less marketable gas; and condensate-blocked pipelines.

Consequently, many laboratory[5,6,11,12,33] theoretical[1,2,4,9-14] and field investigations[10, 15-23] have been conducted over the last forty years to try to understand condensate reservoir flow behavior. It has been found that, when reservoir pressure around a well drops below the dew point pressure, retrograde condensation occurs and three regions are created with different liquid saturations[14,24,25]. Away from the well, an outer region has the initial liquid saturation; next, there is an intermediate region with a rapid increase in liquid saturation and a corresponding decrease in gas relative permeability. Liquid in that region is immobile. Closer to the well, an inner region forms where the liquid saturation reaches a critical value, and the effluent travels as a two-phase flow with constant composition (the condensate deposited as pressure decreases is equal to that flown towards the well). There may also exist a fourth region in the immediate vicinity of the well where low interfacial tensions at high rates yield a decrease of the liquid saturation and an increase of the gas relative permeability[1,9]. The first, third and fourth regions should appear as three different permeability zones in a well test. The existence of the fourth region is particularly important as it would counter the reduction in productivity due to liquid dropout. This "velocity stripping[26]" has been inferred from laboratory experiments and numerical simulations but there has been little evidence of it from well test data published to-date.

The present paper presents preliminary results from a study aimed at developing a better understanding, both qualitatively and quantitatively, of near-wellbore effects in gas condensate reservoirs from well testing. In the study, the conditions of the existence of the different mobility zones due to condensate dropout are investigated by analyzing well test data from numerous gas condensate fields with different characteristics and correlating them to the various reservoir and fluid properties. Particular emphasis is on the identification of the enhanced gas relative permeability region around the well, as it remains a key uncertainty in well deliverability forecasting[1, 10, 23]. The overall objective of the study is to develop new methods for predicting well productivity in gas condensate reservoirs.

Previous work

There are relatively few publications dealing with well testing in gas condensate reservoirs[1, 10, 11, 15, 17, 19, 21]. Published interpretations are performed mainly on build-up data, because drawdown data are usually affected by flow rate fluctuations, and in the particular case of gas condensate wells, by noise due to condensate unloading in the wellbore. Analyses use pressure[1, 12, 17], single-phase pseudo-pressure[11, 12, 21] or two-phase pseudo-pressures[10, 12, 19]. The latter, which require good experimental measurements of relative permeability curves (rare for gas condensate systems) yield homogeneous looking derivatives and give access to the mechanical skin only.

Single-phase pseudo-pressure, on the other hand, yield, often composite-shaped derivatives below the dew point. These usually resemble curve (a) in Figure 1 and suggest the existence of two mobility-zones, one in the vicinity of the wellbore with reduced gas effective permeability due to liquid dropout, and one away from the well, with single phase gas where the reservoir pressure is still above the dew point. Analysis of such build-up data with a two-region composite model provides the total skin and a 2-phase (condensate blockage) skin[19]. The non-Darcy coefficient is often estimated by matching drawdown or rate data with a simulator which includes non-Darcy flow, by adjusting the parameter β of the Forcheimer equation[1, 10].

There has been no published well test data exhibiting a region of increased gas mobility in the immediate vicinity of the wellbore (the fourth region mentioned in the introduction) which should yield a response similar to curve (b) in Figure 1. The only mention of the possible existence of such a zone in field data is found in Ref. 20, where the authors had to incorporate liquid velocity stripping in their simulator to match DST drawdown data from the Britannia field.

Simulation studies

Before proceeding with the analysis of field data, a number of simulations were performed with a compositional simulator (techSIM from AEA Technology), in order to verify the conditions of the existence of the three mobility zones described above and to develop an understanding of the derivative shapes to be expected in a well test[27]. The simulator calculates the fluid PVT properties using an equation-of-state (EOS) and varies condensate and gas relative permeabilities as a function of the capillary number, Nc, according to correlations developed by Henderson *et al.*[28,29]. The simulation model represents a single-well in a homogeneous, radial reservoir of uniform thickness. The reservoir characteristics are constant and are shown in Table 1. The model consists of 40 cells with an outer radius of 11,950 ft to insure that no boundary effects are seen in the simulated well tests. Near the wellbore, the cells are small to simulate the gas-condensate near-wellbore behavior accurately. The cell size increases logarithmically away from the wellbore. The model does not account for wellbore storage and mechanical skin.

The simulation runs are designed to show the gas-condensate behavior under different production conditions. In all cases, the initial reservoir pressure is set to just above the dew point pressure, so that the liquid-phase condensate forms at the start of production. An example of a pressure-rate history for a simulation run is shown in Fig. 2**.** This run consists of 10 periods of alternating draw-downs and build-ups (1DD, 2BU, 3DD, 4BU,…, 9DD, and 10BU). The first drawdown is extended (100 days) to allow for the condensate to accumulate in the near-well bore region, and the subsequent periods are ten days long. Variations of this production history are run with different rates, gas-oil relative permeability models, and fluid compositions.

Fig. 3 shows how the liquid condensate (So) builds up around the wellbore during the first production period, 1DD, with and without capillary number (N_c) effects. Capillary number effects reduce the condensate saturation around the well and in the reservoir. As time increase, the reduction is greater in the immediate vicinity of the wellbore and the saturation takes a ‘doughnut’ shape around the well. The corresponding gas relative permeability, shown in Figure 4, exhibits a minimum between 10 and 100 feet in our example, a maximum corresponding to the single phase gas away from the well and an intermediate value in the few feet around the well. These are the three mobility regions discussed in the introduction and should yield three stabilizations on the derivative.

The derivatives of the shut-in period, 2BU, following the initial, extended drawdown, are shown in Figure 5 in terms of single-phase pseudo-pressure, with and without N_c effects. As expected from the condensate saturation distribution (Figure 3), the early-time mobility is much lower without N_c effects than with N_c effects. The three stabilizations on the derivative with N_c effects are not obvious, but should exist as indicated in Figure 5, based on the gas relative permeability distribution in Figure 4. There should be only two stabilizations without Nc effects.

Figure 5 is for a lean gas. The same test was simulated for a rich gas and the gas relative permeability distributions are compared in Figure 6. The rich gas does not show a minimum and the corresponding derivative should have two stabilizations only, as illustrated in Figure 7.

The simulation study thus confirms that, when capillary number effects are important, the pressure derivative should exhibit three stabilizations. In our example, the differences between the various stabilizations are very small: the permeability thickness selected was 1000 mD.ft, which seems to be the limit beyond which well productivity is no longer affected by condensate deposition[30]. Lower permeability-thickness values should yield greater contrast between stabilization levels.

Impact of wellbore dynamics

When looking at field data, it becomes obvious that one reason for the lack of well tests showing a zone of increased gas mobility around the wellbore is that such data are difficult to identify with confidence. When they may exist, they are also likely to be hidden by wellbore phase redistribution effects. Phase redistribution occurs when different phases flow in different directions in the wellbore. Typical examples are oil and water, gas and water, gas and liquid condensate, and oil and gas in gas-lifted wells. It creates an *increase* in the wellbore storage coefficient and may be present in drawdowns or in build-up's. This is different from a phase change, which creates a *decrease* in the wellbore storage coefficient in a build-up and an *increase* in the drawdown. The impact of phase change on the pressure behavior is usually limited to early times whereas an increase in wellbore storage due to phase redistribution may dominate the test for many hours.

Recognizing the existence of wellbore phase redistribution is important because it can create derivative shapes which could be easily misinterpreted as they are similar to what would be obtained with double porosity, partial penetration or composite behaviors. Typical derivative shapes due to phase redistribution (whether in a drawdown or in a build-up) are shown in Figure 8. Curve (5) in Figure 8 corresponds to the denser phase being re-injected into the formation.

An example of how phase redistribution can affect multiphase flow pressure behavior and therefore the analysis of the data is shown in Figure 9. Figure 9 is a log-log plot of rate normalized pressure and pressure derivative for a drawdown and the following build-up in a North Sea well producing oil and water (Well A). Rate normalized means that the pressure change and the derivative have been divided by the applicable rate so that the derivatives stabilize at the same level during radial flow in all the flow periods. In Figure 9, the drawdown and build-up derivatives are different at early times, as the well was open at the surface for the drawdown, and shut-in downhole for the build-up. They also, however, differ at late times, with different apparent radial flow stabilizations. Interpretation of production logs run during both drawdown and build-up points to reverse water flow in the wellbore during build-up. This suggests that the build-up is entirely dominated by increasing wellbore storage and therefore is not interpretable. Analysis in this example has to be performed on the drawdown.

The same phenomena is often seen in gas wells producing water. Figure 10 shows the pressure and rate history during a well test in a dry gas well in Canada (Well B). One build-up and five drawdowns are presented on the rate-normalised log-log plot of Figure 11. Data in Figure 11 are plotted in terms of normalized pseudo-pressure[10]. The drawdown called "Flow period 2" is at the beginning of the test, and is followed by the build-up (Flow period 4). All drawdowns in Figure 11 except the one corresponding to Flow period 15 exhibit similar shapes (except for differences in skin and wellbore storage at early times) and tend towards the same derivative radial flow stabilization at late times. The behavior of the build-up (Flow period 4) and of the drawdown Flow period 15, on the other hand, are very different. This can be explained as follows: during a drawdown, a mixture of gas and water droplets flows up the well. When the well is shut-in, the droplets remain suspended for a little while and then drop down, creating a liquid cushion at the bottom of the well which may even be reinjected into the reservoir, by gravity or by expansion of the gas at the top of the well. This results in an increase in wellbore storage effects which could dominate the entire build-up behavior and render the analysis impossible. This does not happen in drawdowns unless the concentration of denser fluid in the wellbore is such that it cannot be lifted by the gas to the surface. This would occur in drawdowns with low flow rates, or in drawdowns following a previous drawdown at a higher rate, such as Flow period 15. In the particular example of Figure 11, although the shape of the build-up resemble that of a composite behavior, the build-up is entirely dominated by wellbore phase redistribution and not interpretable: analysis with a composite model would overestimate the gas mobility by a factor 3. Here again, analysis must be performed on the drawdowns (Flow period 2).

Phase redistribution is also present in drawdowns and build-up's from gas condensate wells. Figure 12 is a rate-normalized log-log plot of drawdown data (Flow periods 7, 14, 15 and 18) for a North Sea lean gas condensate well (Well C). Pressures and derivatives are expressed in terms of single-phase normalized pseudo-pressure[10]. Drawdown data are obviously dominated by increasing wellbore storage. As should be expected, this effect seems more pronounced and appears to last longer for low flow rates (Flow periods 14, 7 and 15). The higher rate drawdown Flow period 18 seems less affected compared to the other drawdowns. Its derivative is similar to that for the build-up's, Flow periods 8, 18 and 21, shown in Figure 13. Close inspection of the build-up's shows that they also are affected by phase redistribution in the period 1 to 10 hours, so it is possible that the drawdown Flow period 17 is affected as well. This has to be taken into account when performing the analysis.

Early time well test behavior of gas condensate wells

One of the objective of our study is to confirm the existence of "velocity stripping" in gas condensate wells from well test data. This refers to an enhanced gas mobility zone at high rates in the immediate vicinity of the wellbore due to high capillary numbers. We are therefore looking for derivatives exhibiting a three-region composite behavior, similar to curve (b) in Figure 1. As discussed in the previous section, the challenge is to avoid data affected by wellbore phase redistribution.

Data for Well C in Figure 13 seem to show a three-region composite behavior and therefore could be interpreted to quantify the three mobility zones defined in the introduction. The analysis is best performed on the drawdown data Flow period 17, as it is the longest period of the test and shows more of the various composite features. The final derivative stabilization, corresponding to the mobility of the gas with the initial condensate saturation, is easy to locate, slightly below the last data points after 100 hours. The derivative stabilization corresponding to the increased condensate saturation is equally easy to locate, at the level of the derivative hump around 10 hours. The location of the derivative stabilization corresponding to the enhanced gas mobility, on the other hand, is much more difficult to find. It must be between the other two, and therefore cannot correspond to the minimum at 1 hour. This minimum must correspond to wellbore phase redistribution effects, as suggested by the shapes of the build-up's in Figure 14. There is therefore a significant uncertainty in this particular example.

When a choice has been made for the first stabilization, the analysis can be performed with a three region composite model[31] (Figure 15), based on a solution by Satman, *et al*.[32]. The log-log match with such a model is shown in Figure 16: (1) represents the three-region composite model with no wellbore storage and skin; (2) is the same solution for constant wellbore storage; and (3) is the changing wellbore storage solution. The latter also provides a good match on the superposition plot and for the simulation of the entire test. The internal and external radii of the condensate "doughnut" are 100 and 500 feet, respectively.

Another example of the possible existence of three derivative stabilizations is shown in Figure 17. The data are from Well D, another North Sea lean gas condensate reservoir. They can be interpreted with either a two-region or a three-region composite model. Both analyses give parameter values which are reasonable. The complete analysis is shown in Figures 18 to 20 (respectively, Horner match, simulation, and skin versus rate plots). It yields all the components of the skin factor.

Discussion and Conclusions

This paper presents the preliminary results of a systematic study of well tests in gas condensate reservoirs. One of the primary objectives is to investigate the conditions of the existence of the different mobility zones due to condensate dropout and velocity stripping.

It was found that phase redistribution is a major problem in analyzing the data. It not only reduces the amount of data available for analysis, but may also create drawdown or build-up shapes that can easily be misinterpreted for reservoir behaviors.

Examples have been shown that seem to exhibit three stabilizations on the derivative, corresponding to three mobility zones: (1) an outer zone away from the well, with the initial liquid condensate saturation; (2) a zone nearer to the well, with increased condensate saturation and lower gas mobility; and (2) a zone in the immediate vicinity of the well with high capillary number which increases the gas relative permeability, resulting in a recovery of much of the gas mobility lost from condensate blockage.

These results have to be considered with caution, however, until more systematic evidence of such behavior becomes available.

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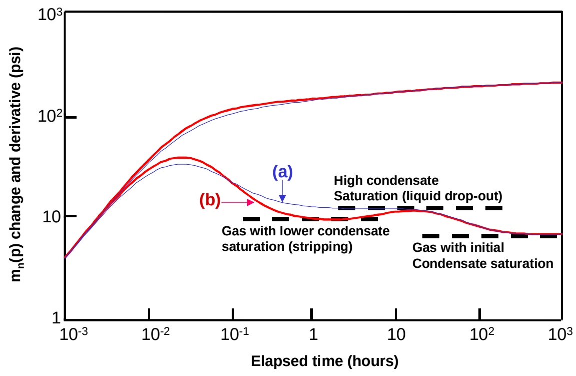

Fig. 1: Schematic of pressure and derivative composite behavior: (a) two-region composite; (3) three-region composite

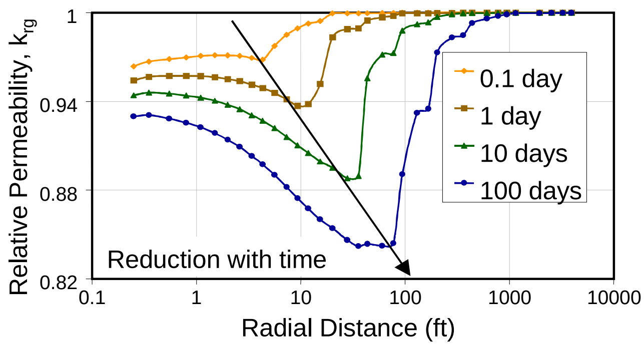

Fig. 4: Gas relative permeability distribution in the reservoir during the first extended drawdown

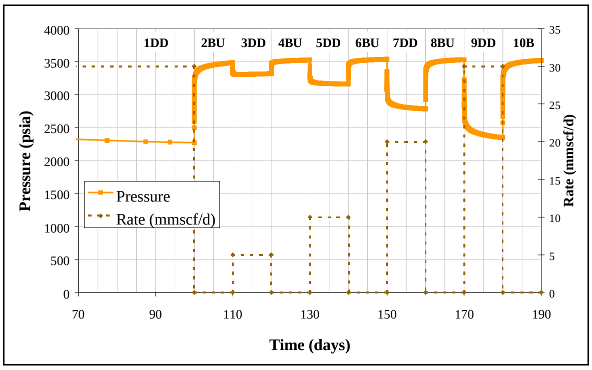

Fig. 2: Rate & Pressure History Example for the Simulation Runs.

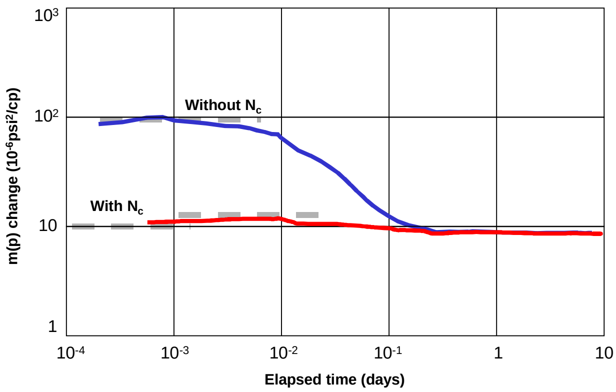

Fig. 5: Log-log pressure derivatives for the build-up following the first extended drawdown

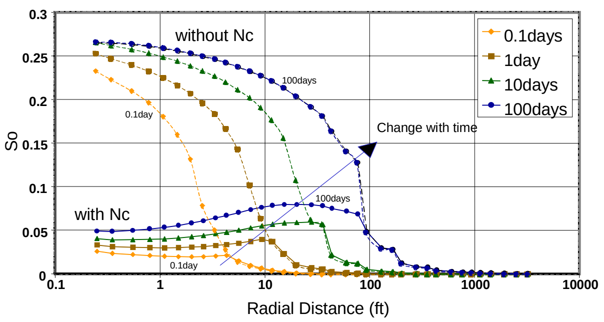

Fig. 3: Saturation distribution in the reservoir during the first extended drawdown

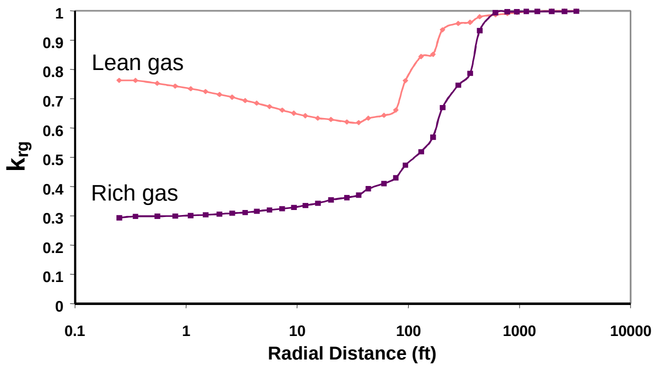

Fig. 6: Gas relative permeability distribution for lean and rich gases during the first extended drawdown

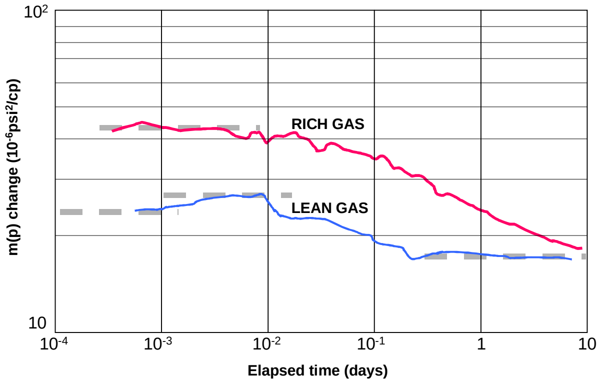

Fig. 7: Log-log pressure derivatives for the build-up following the first extended drawdown

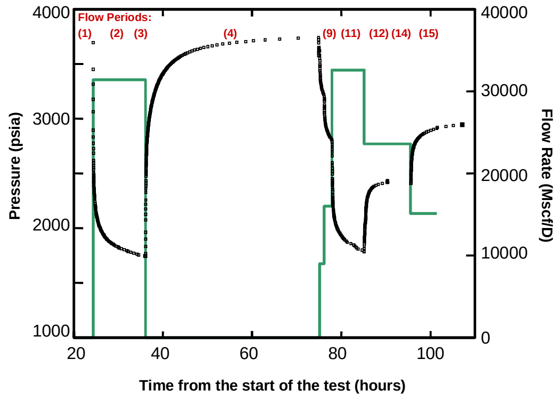

Fig. 10: Pressure and rate test history, dry gas Well B

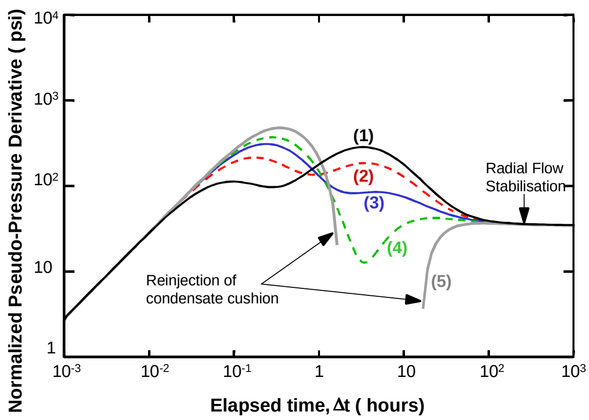

Fig. 8: Log-log derivative plots, increasing wellbore storage due to phase redistribution in the wellbore

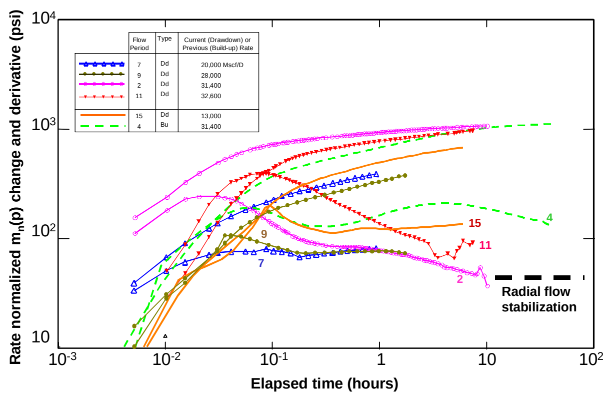

Fig. 11: Log-log plot, dry gas Well B, showing increasing wellbore storage due to phase redistribution in the wellbore during build-up and decreasing rate drawdown

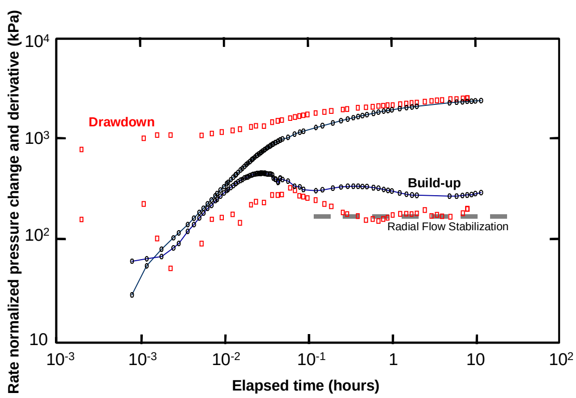

Fig. 9: Log-log plot, oil/water Well A, showing increasing wellbore storage due to phase redistribution in the wellbore during build-up

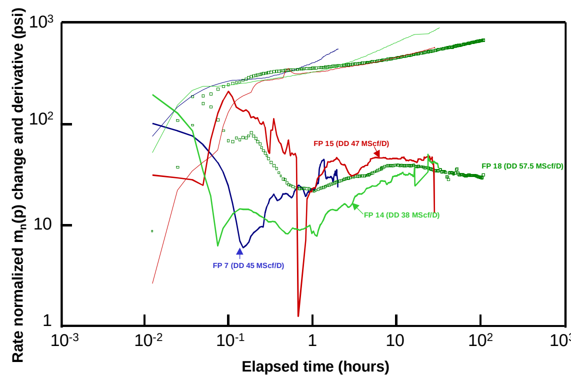

Fig. 12: Log-log plot, gas condensate Well C, showing increasing wellbore storage due to phase redistribution in the wellbore during low rate drawdowns

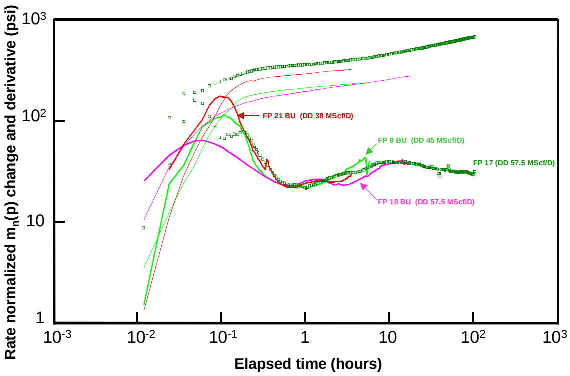

Fig. 13: Log-log plot, gas condensate Well C, showing little phase redistribution in the wellbore during build-up's and high rate drawdown

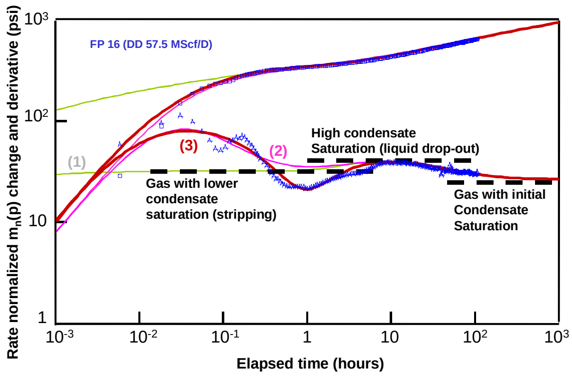

Fig. 16: Analysis of gas condensate Well C with the three-region composite model (Log-log Match)

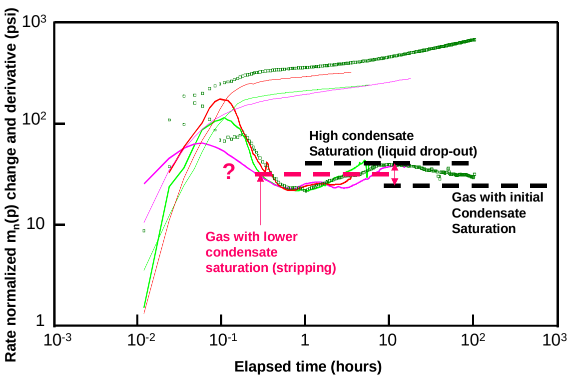

Fig. 14: Log-log Diagnostic Plot for Well C

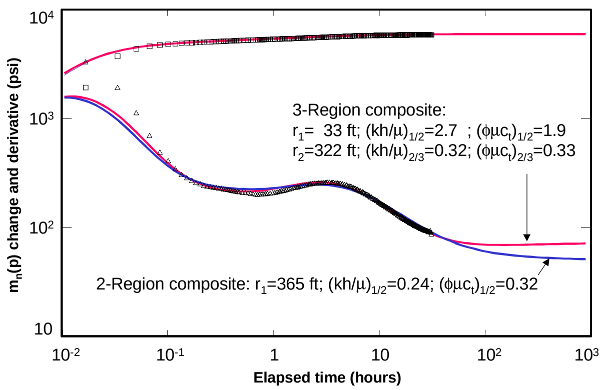

Fig. 17: Analysis of gas condensate Well D with the three-region composite model (Log-log Match)

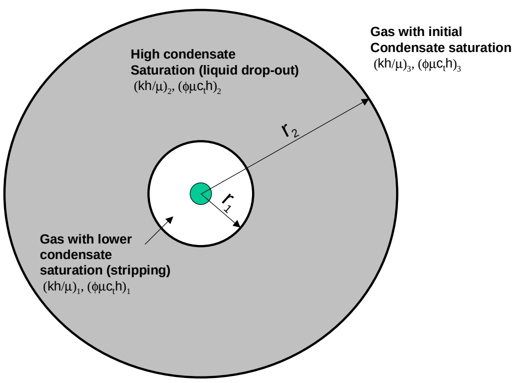

Fig. 15: Schematic of three-region composite model

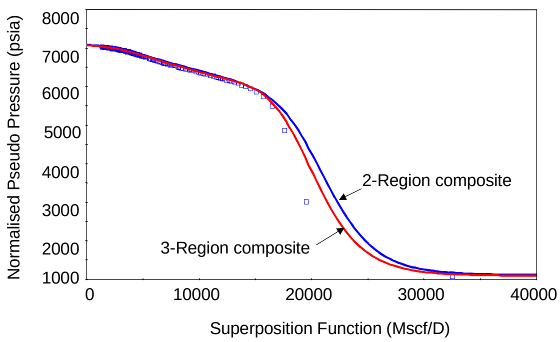

Fig. 18: Analysis of gas condensate Well D with the three-region composite model (Horner Match)

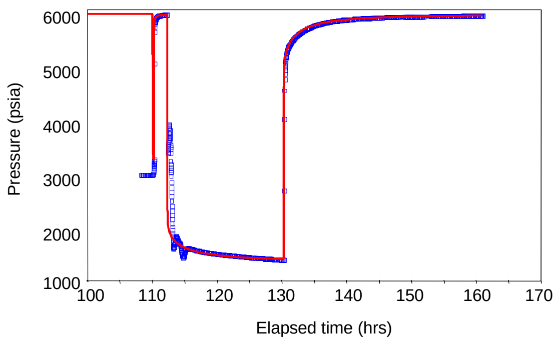

Fig. 19: Analysis of gas condensate Well D with the three-region composite model (Horner Match)

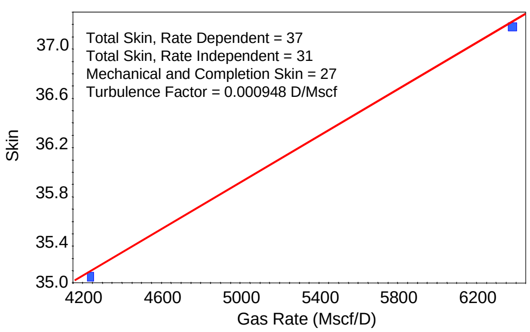

Fig. 20: Skin versus rate, Well D

Parameters	Value
Porosity	0.1
Absolute permeability	10 mD
Net-to-gross ratio	1
Conate water saturation	0.15
Wellbore radius	0.25 ft
Top Depth	8500ft
Initial Reservoir Pressure (lean gas)	3600 psia
Initial reservoir Pressure (rich gas)	6400 psia

Table 1: Parameters for simulations