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Calculating Well Deliverability in Gas Condensate Reservoirs

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Abstract

Well deliverability in most gas condensate reservoirs is reduced by condensate banking when the well bottom hole pressure falls below the dew point, although the impact of condensate banking may be reduced due to improved mobility at high capillary number in the near-well region.

Calculating well productivity in field-scale simulation models can be difficult because of the need to model phenomena which occur at high flow rates within a few feet of the wellbore. We review three different approaches for calculating condensate well productivity in full field reservoir simulation

1) Using single well calculations to estimate skin factors
2) Local grid refinement
3) Pseudopressure methods.

The pseudopressure technique can be extended to include high flow rate effects such as non-Darcy flow and changes in relative permeability at high capillary number. The paper compares simulation results using the pseudopressure method and fine scale simulation.

The paper also discusses the use of pseudopressure methods in spreadsheet calculations to estimate well deliverability. The results generally show good agreement with those from fine grid simulation models, so that spreadsheet models can be used as a quick way of estimating well deliverability.

Introduction

Well productivity is a critical issue in the development of many gas condensate reservoirs. Liquid build-up around the well can cause a significant reduction in productivity, even in lean gas condensate reservoirs where the maximum liquid drop out in the deep reservoir is as low as 1% [1]. It is essential to take account of this 'condensate blockage' effect when calculating well productivity.

Much of the pressure drop from condensate blockage occurs within a few feet of the wellbore, where flow rates and capillary numbers are very high. There is growing body of experimental evidence to show that gas condensate relative permeabilities are increased at high capillary number [2, 3], reducing the adverse impact of condensate blockage. Analysis of well test results has also shown that simulation with conventional relative permeability models tends to underestimate well productivity [1, 4, 5]. Inertial or non-Darcy flow effects may also be important in gas condensate wells producing at high flow rates.

As many of the phenomena affecting condensate blockage occur close to the well bore, it can be difficult to represent condensate blockage effects in field scale reservoir simulation models on a coarse grid. The aim of this paper is to review practical techniques for calculating condensate well productivity, both in field scale simulation models and in simple engineering calculations.

Conventional Simulation Methods

The traditional approach to modelling gas condensate well productivity in field scale simulation is to use single well radial models to estimate skin factors due to condensate blockage, and to use these skin factors in the field scale simulation. This is not ideal, as the skin factor may vary with pressure and flow rate, and there can be problems in ensuring consistent conditions between the single well and full field models.

To illustrate the need for a fine grid, Figure 1 compares results from one dimensional single well radial simulations on a rich gas condensate (dew point pressure about 6000 psi) in a model reservoir with a permeability of 10 md and thickness of 100 feet. The well was produced at a plateau gas production rate of 40 MMscf/day with a limiting bottom hole pressure of 1500 psi. Four simulation models were run

1) 2 grid cells, inner grid cell Δr = 1500 feet,
2) 6 grid cells, inner grid cell Δr = 100 feet,
3) 12 grid cells, inner grid cell Δr = 0.5 feet,
4) 36 grid cells, inner grid cell Δr = 0.1 feet.

Figure 1 shows the results for gas production rate as a function of reservoir pressure. (Note that the pressure scale is in reverse order so that early time behaviour is on the left). There is very little difference between the 12 and 36 cell models, but the other two models overestimate well productivity. Figure 1 also shows the condensate blockage 'skin' - this is the skin factor which would be needed in the 2 cell model to replicate the results of the 36 cell model. The skin varies significantly with pressure, making it difficult to model well productivity by increasing the skin factor in a coarse grid model.

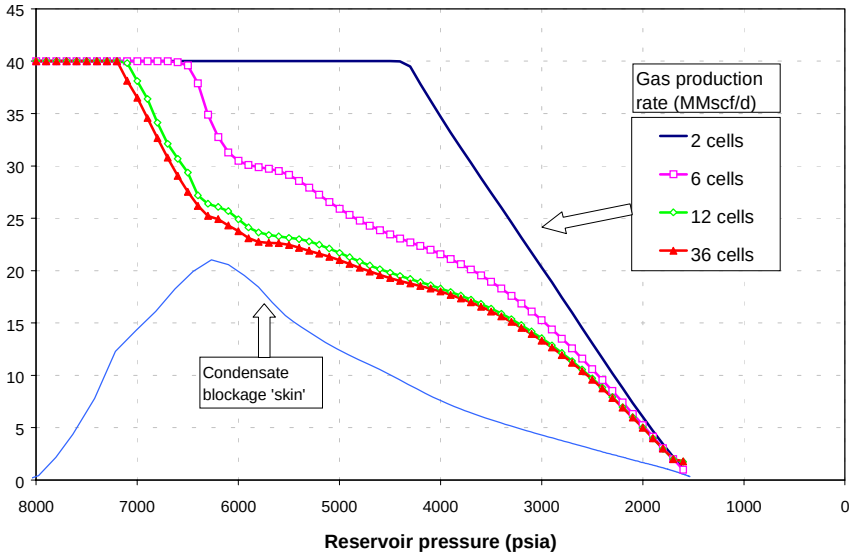

Figure 1. Effect of different radial grids on simulations of gas condensate well productivity.

Local Grid Refinement (LGR) can be used to model near well effects in field scale simulation. A radial grid can be embedded within a single column of grid cells in the full field model. However,

the use of LGR's results in a much more complex simulation model, can lead to a significant increase in run time, and may cause numerical problems in linking the solutions on the local and global grids.

Pseudopressure Methods

Theory

An alternative method of calculating condensate well productivity in field scale simulation is to use the pseudopressure method of Fevang and Whitson [6]. Their analysis is based on dividing the area around the well into three regions

- Region 1, where both condensate and gas are mobile, and the flowing composition is constant.
- Region 2, where the condensate saturation is building up. The condensate is immobile or has low mobility.
- Region 3, where no condensate phase exists (above the dew point).

These regions are illustrated in Figure 2, which shows the condensate saturation, flowing composition and pressure as a function of radius (note the log scale). The flowing composition is represented by the C7+ mole fraction in the flowing fluid (in both the condensate and gas phases).

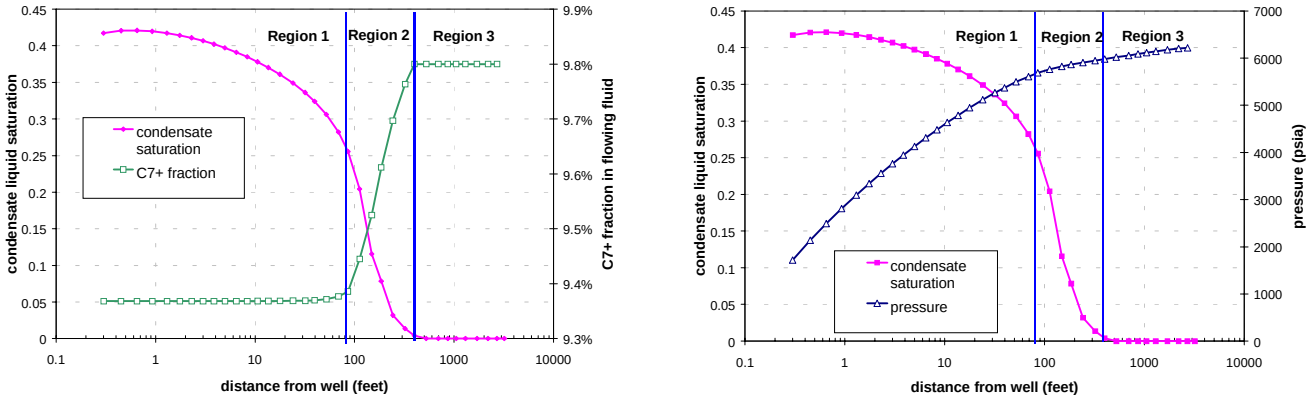

Figure 2. Condensate saturation, flowing C7+ fraction and pressure versus radius.

As most of the pressure drop occurs in Region 1, it is the most important region for calculating condensate well productivity. In Region 1, the flowing composition is constant and a semi-steady-state regime exists, so that the phase mobilities must satisfy the relation

$$\frac{k_{rg}/\mu_g}{k_{ro}/\mu_o} = \frac{V_g}{V_o} \tag{1}$$

where V_g and V_o are the gas and oil phase volumes from a constant composition expansion on one mole of the flowing fluid composition. In the gas condensate pseudopressure model, the gas flow rate of component *m* from a well is given by

$$q_m = \frac{2\pi kh}{\ln(r_e/r_w)} z_m \left(m(P_j) - m(P_w) \right) \tag{2}$$

and the pseudopressure integral is defined by (using equation 1 to derive the second form)

$$m(P) = \int_{P_{ref}}^{P} \left(\frac{k_{rg}c_g}{\mu_g} + \frac{k_{ro}c_o}{\mu_o} \right) dP = \int_{P_{ref}}^{P} \frac{k_{rg}}{\mu_g V_g} dP \tag{3}$$

There are some points worth emphasising on equations 1 to 3. From equation 1 we can derive the ratio k_{rg}/k_{ro} in Region 1 as a function of pressure, the flowing fluid composition and the fluid PVT properties. Equation 3 shows that the well production rate is directly dependent on k_{rg} in Region 1. Hence the key parameter in determining condensate blockage is the relationship between k_{rg} and the ratio of k_{rg}/k_{ro}. Equations 2 and 3 differ from the standard dry gas pseudopressure method in that the relative permeability is included within the pseudopressure integral.

The pseudopressure integral is based on Region 1 for all pressures below the dew point. It is not possible to model Region 2, as condensate is accumulating in Region 2 and the steady state assumption is not valid. The neglect of Region 2 is not particularly serious in terms of the pressure drop, but it may be important in its effect on the fluid composition used in Region 1.

The left hand diagram on Figure 2 shows that the flowing C7+ fraction is lower in Region 1 than in the deep reservoir, due to the loss of liquid components as the condensate saturation builds up in Region 2. The pseudopressure integral is often very sensitive to the flowing fluid composition, and the need to estimate the flowing composition accurately is an important issue in practical application of the pseudopressure method.

Simulator implementation

We have implemented the pseudopressure integral in a compositional and black oil reservoir simulator to test its accuracy. At each timestep, a table of pseudopressure versus pressure is calculated for each well completion, using the flowing fluid composition from the previous timestep. The maximum and minimum pressures in the table are the grid block pressure and the limiting bottom hole pressure for the well. The integration is carried out numerically, and between 5 and 10 pressure intervals are normally adequate.

The pseudopressure integral involves calculating k_{rg} at a given value of k_{rg}/k_{ro}. When k_{ro} is derived from a three-phase model, an iterative method is used to calculate k_{rg} at a given value of k_{rg}/k_{ro} and water saturation.

High flow rate effects

The pseudopressure well model in the reservoir simulator has been extended to include a model for changes in relative permeability at high capillary number [7]. The pseudopressure integral requires the calculation of k_{rg} from k_{rg}/k_{ro}, and this calculation needs to take account of the capillary number. At each pressure in the pseudopressure integration, we estimate the radius at which this pressure occurs using the equation

$$\frac{\ln r - \ln r_w}{\ln r_e - \ln r_w} = \frac{m(P) - m(P_w)}{m(P_j) - m(P_w)} \tag{4}$$

where the pseudopressure, well pressure and grid block pressure are taken from the previous timestep. When the radius is known, it is possible to derive the Darcy velocity and capillary number at the given pressure. An iterative method is then used to calculate k_{rg} at the required values of k_{rg}/k_{ro}, capillary number and water saturation. This is similar to the method of Fevang and Whitson [8], except in the use of equation 4 to estimate radius in terms of pressure.

The same approach can be used to include the effects of non-Darcy flow. At each pressure point in the pseudopressure integral, we calculate a non-Darcy flow multiplier which reduces the effective gas permeability.

Simulation Results

Figure 3 show the results of using the pseudopressure method to calculate well productivity in the same 1D model reservoir as in Figure 1. The pseudopressure method underestimates the productivity when used in the model with 2 grid cells, but gives a good match to the fine grid results when used in the model with 6 grid cells.

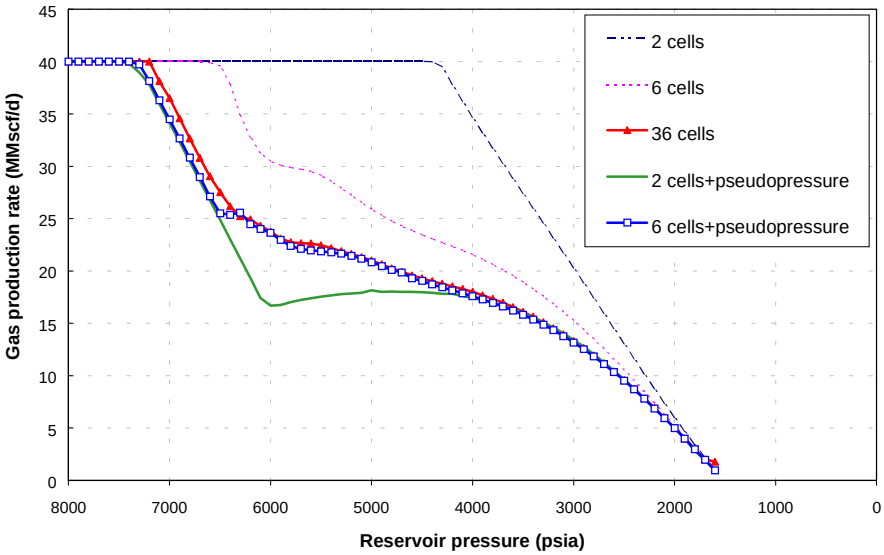

Figure 3. Gas production rate from different 1D simulation models

The low productivity in the 2 cell model is due to an inaccurate flowing composition. The pseudopressure is very sensitive to the flowing composition, and the left hand chart on Figure 2 shows that the flowing composition is constant up to about 100 feet from the well. The inner grid cell in the 6 cell model has an average radius of about 60 feet, so that the flowing composition is calculated accurately. On the other hand, the inner grid cell in the 2 cell model has an average radius of about 600 feet, so that the liquid fraction in the flowing fluid is overestimated, and the calculated condensate blockage skin is too large.

We have observed similar results in a number of calculations with different fluids and relative permeability models. As a general rule, the pseudopressure integral gives good results when the inner grid cell dimensions are less than a few hundred feet.

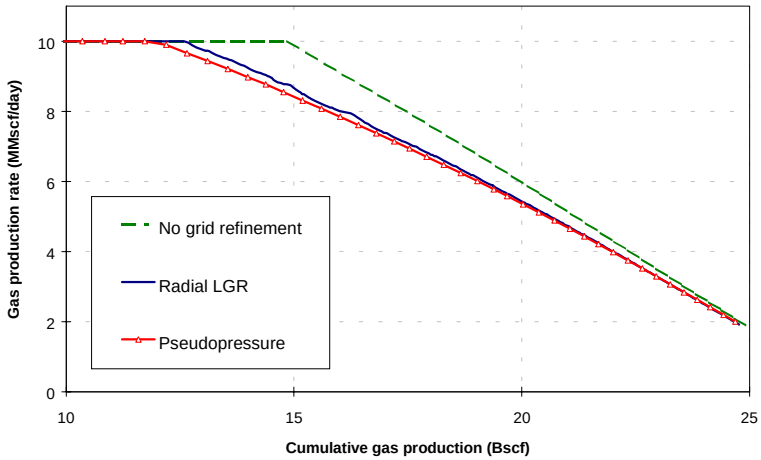

Figure 4. Gas production rate from 3D simulation models

Figure 4 shows results for a 3D compositional simulation model on a 12x12x5 Cartesian grid, where the areal dimensions of each grid cell were 300 feet by 300 feet. A vertical production well was placed near to the centre of the model, and completed in all 5 layers. The permeability varied between layers. The well was produced at a plateau gas production rate of 10 MMscf/day with a limiting bottom hole pressure of 2000 psi. Three simulation runs were made

1. Regular grid with no local refinement or pseudopressure.
2. Radial local grid refinement (LGR) in the column of blocks where the well was completed. There were 4 cells in the radial direction, with the inner cell having dimensions of about 1 foot. Local timestepping was used on the radial grid.
3. Regular grid with pseudopressure.

If we assume that the LGR calculation gives the most accurate result, the simulation with a regular grid overestimates productivity significantly. Using pseudopressure in the regular grid gives results which are much closer to the LGR run, but with the gas rate slightly lower after the end of the plateau production period.

The computing times for these simulations showed that the pseudopressure calculation increased the run time by about 10%, whereas the radial LGR increased the run time by 140%.

The results in Figure 5 show the impact on well productivity of allowing oil and gas relative permeabilities to vary with capillary number in the same the 1D simulation model as in Figures 1 and 3. The parameters for the capillary number effect were derived by matching experimental data on a sandstone core. The capillary number effect causes a significant increase in well productivity, and there is an excellent match between the results of fine grid simulations and coarse grid simulation with the pseudopressure well model.

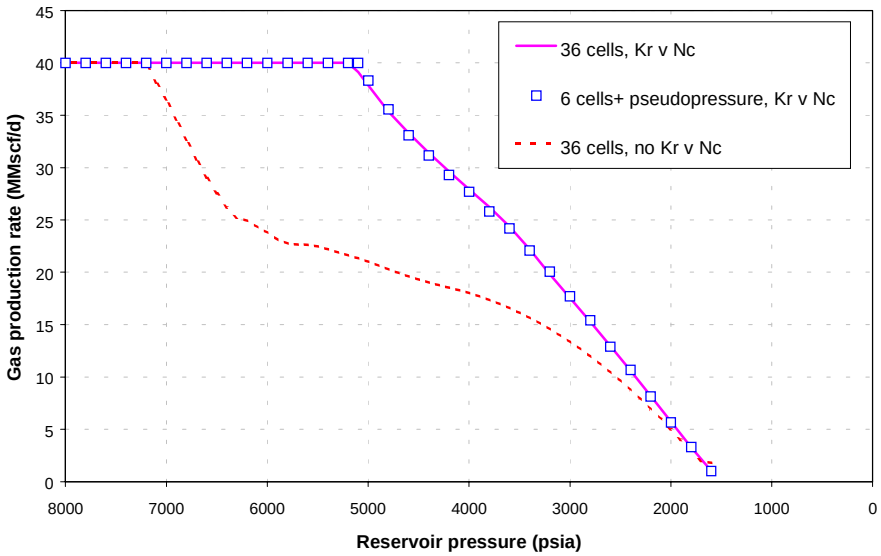

Figure 5. 1D simulation model results where relative permeability depends on capillary number

Spreadsheet Models

The pseudopressure method can also be used in simple engineering calculations, and we have developed an Excel spreadsheet to estimate gas condensate well productivity and calculate production profiles. The spreadsheet model allows quick estimates of gas condensate well performance without the effort of setting up a reservoir simulation model, and is particularly useful for sensitivity studies to determine the most important parameters affecting well productivity.

The spreadsheet combines a material balance model of the reservoir with a pseudopressure model for well productivity. Relative permeabilities are calculated from Corey functions, and include options for capillary number effects and non-Darcy flow. The material balance model assumes that the reservoir contains connate water, and that liquid is immobile away from the near-well region.

Fluid properties are calculated from a modified black oil model. When using a black oil model to calculate condensate well productivity, it is important to modify the oil viscosities to reflect the values in the near well region, which are usually lower than in a constant volume depletion at the same pressure [6].

At each pressure in the black oil PVT table, the spreadsheet calculates the maximum gas production rate from the well inflow equation (2). After allowing for a plateau gas production rate, this gives a table of gas production rate versus reservoir pressure. This table is combined with a material balance simulation to give gas and oil production profiles. An Excel macro is used to control the calculations.

The flowing oil-gas ratio (OGR) is an important parameter in the pseudopressure integral. The spreadsheet contains two options for estimating the flowing OGR at a reservoir pressure P. The first method uses the OGR in the gas phase at pressure P – this is termed the CVD MB method in Reference 6. This method tends to underestimate well productivity because it ignores the reduction in the flowing OGR due to Region 2 (for the same reasons as the 2 cell pseudopressure simulation in Figure 3).

To avoid this problem we have developed a new method which estimates the growth of Region 1 as reservoir pressure declines, and calculates the pressure at the edge of Region 1. The flowing OGR is then assumed to be the saturated gas OGR at this pressure.

Figure 6 shows a comparison between gas production profiles calculated using 1D compositional simulation and material balance spreadsheet models. The results in the left hand chart in Figure 6 are with a standard relative permeability model, while the right hand chart shows results including capillary number dependence. These results show how the CVD MB method tends to underestimate well productivity, while the new method gives reasonable agreement with fine grid simulation.

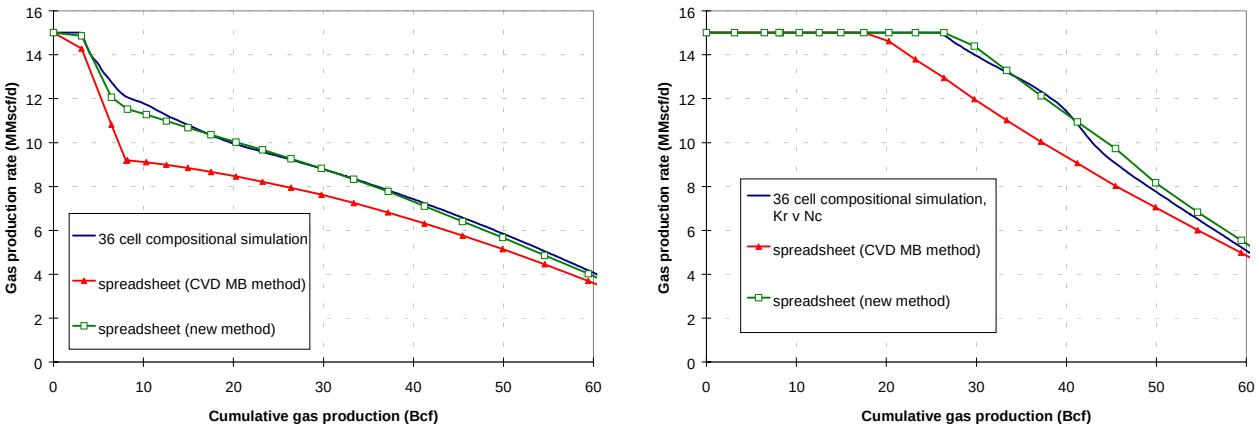

Figure 6. Gas production profiles from spreadsheet and compositional simulation models.

Summary and Conclusions

1) The pseudopressure model provides a practical technique for calculating gas condensate well productivity in field scale simulation models. Provided that the well grid bock size is no larger than a few hundred feet, the pseudopressure method gives good agreement with fine grid simulation.

2) The pseudopressure model can be extended to include the effect of changes in relative permeability at high capillary number and non-Darcy flow, and still gives results which are consistent with fine grid simulation.

3) The pseudopressure model can be used in material balance calculations of gas condensate well performance, but special methods are needed to estimate the flowing fluid composition in the pseudopressure integral.

Symbols

c	molar density
kh	permeability times net thickness
k_r	relative permeability
m	pseudopressure
P	pressure
r_e	pressure equivalent radius
r_w	well radius
V	Phase volume in CCE
z	mole fraction
μ	viscosity

Subscripts

g	gas phase
j	grid block j
m	component
o	oil phase
w	well

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