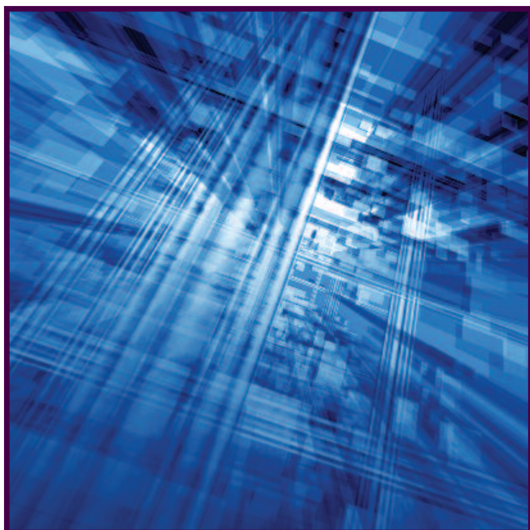

Permeability of Stress-sensitive Formations: its Importance for Shale Gas Reservoir Simulation and Evaluation

E.H. Rutter, R. McKernan, J. Mecklenburgh, S.E. May
Rock Deformation Laboratory, School of Earth, Atmospheric and Environmental Sciences,University of Manchester, Manchester M13 9PL, UK
Email: e.rutter@manchester.ac.uk

Ernest Rutter

Rosanne McKernan

Julian Mecklenburgh

Steven May

Reservoir simulation is essential to the interpretation of well flow tests, and in turn for the estimation of reservoir capacity and flow potential. Permeability of many reservoir rocks may be reduced by overburden pressure, and it is important to incorporate this into reservoir modelling.

Solutions to the transport equation for flow through a porous medium, where *D* is the hydraulic diffusivity, *p* is fluid pressure and t is time, form the basis of making such interpretations.

$$\nabla^2 p = \frac{1}{D}\frac{\partial p}{\partial t} \qquad (1)$$

Hydraulic diffusivity is related to physical properties of the fluid medium and the host rock by $D = k/\phi\mu c$ in which ϕ is rock porosity, *k* is permeability, μ is fluid viscosity and *c* is the combined compressibility of the fluid and porous matrix of the rock. For flow of a near incompressible fluid such as oil, the terms in *D* are not strongly dependent upon pressure and time, hence equation (1) forms a linear partial differential equation and analytic solutions can be obtained.

In the case of a gas, however, *c* depends strongly upon pressure, which causes (1) to become non-linear. Al-Hussainy[1] proposed a pseudofunction given by

$$m(p) = 2\int_{p_0}^{p} \frac{p}{z\mu}\mathrm{d}p \qquad (2)$$

in which *z* is gas deviation factor, to take account of gas property variations with pressure. Re-casting (1) with the pressure variable replaced by *m(p)* re-linearises the transport equation and permits analytic solutions to be found. However, it is still assumed that rock permeability is insensitive to the effective pressure (total pressure – pore fluid pressure) acting on the rock. In the simplest case, effective pressure, which tends to close pore spaces and particularly the pore throats that interconnect the pore spaces, is given by the difference between the mean pressure on the rock mass (largely due to the weight of overlying rocks) and the pore fluid pressure (whether gas or liquid). For relatively permeable rocks, in which pore throats may be large and do not close significantly when effective pressure increases, the assumption that the permeability is insensitive to effective pressure can be a reasonable and is routinely applied to the evaluation of conventional gas reservoirs.

Permeability of gas shales

For unconventional reservoirs such as gas shales, grain size and pore spaces are of small dimensions, and pore throat diameters typically are sub-micron in size. They are more easily closed by application of effective pressure. Such reservoir rocks are described as 'stress-sensitive', so that as gas pressure drawdown occurs during production, permeability varies with effective pressure and time throughout the reservoir.

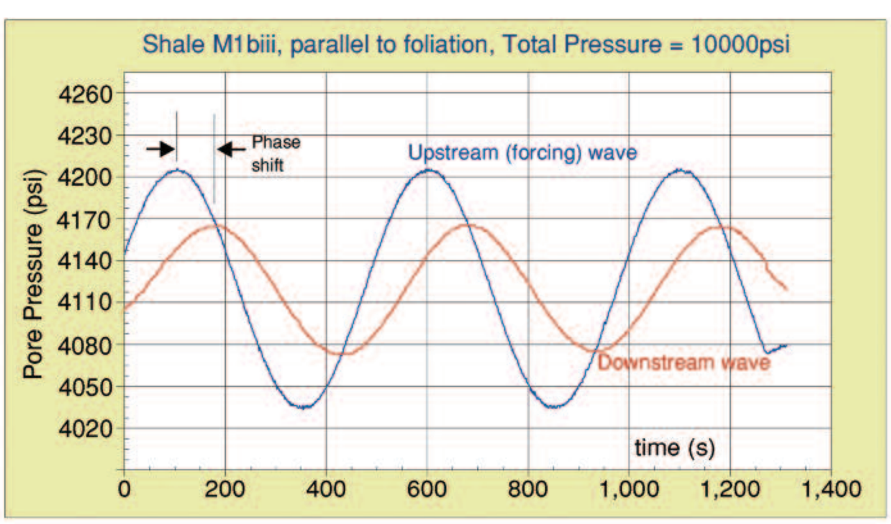

Figure 1: Example of experimental data from a permeability measurement by the oscillating pore pressure method with a mean pore pressure of 4120 psi and a total confining pressure of 10000 psi. Relative to the upstream forcing wave the downstream wave is reduced in amplitude and is phase-shifted. The permeability is largely determined by the amplitude ratio, and is in this case 20 μD.

It is common for reservoirs to display reduced permeability close to a production borehole, as a result of formation of a 'skin' of damaged rock where drilling fluids may have been forced into pore spaces. This effect appears in solutions to (1) as an increased pressure drawdown term that can be interpreted as a reduced overall reservoir permeability, thereby ignoring the essential stress sensitivity of the reservoir.

Permeability is one of the more time-consuming rock physical properties to measure, especially in the case of shales and other fine-grained rocks where its value may be very low. A commonly employed measurement technique is the GRI (Gas Research Institute) method, which measures intergranular permeability in an aggregate of 0.7 mm diameter rock particles to avoid the presence of cracks. Unfortunately the measurement can only be made at near zero effective pressures when permeability is at its highest, and no information about stress sensitivity or anisotropy is obtained. Using GRI data in reservoir simulations will lead to an over-optimistic assessment of potential and a large divergence from in-situ permeabilities estimated from well tests.

Permeability under effective pressure conditions can be measured on core plugs using steady-state flow methods (slow) or pulse transient decay methods (Brace et al.[2]), but we feel that the oscillating pore pressure method (Kranz et al.[3]; Fischer[4]; Faulkner & Rutter[5]; Bernabé et al.[6]) is the best method to assess the behaviour of stress-sensitive reservoir rocks. A sinusoidally-varying, low-amplitude (e.g. 75 to 150 psi) pore pressure wave is applied to the upstream end of a jacketed core plug subjected to a higher hydrostatic pressure to simulate depth of burial. At the downstream end the same wave, reduced in amplitude and shifted in phase is detected. From the amplitude loss and phase shift the permeability and sample storativity can be calculated. Unlike others, the method is robust and insensitive to small amounts of pressure leakage and

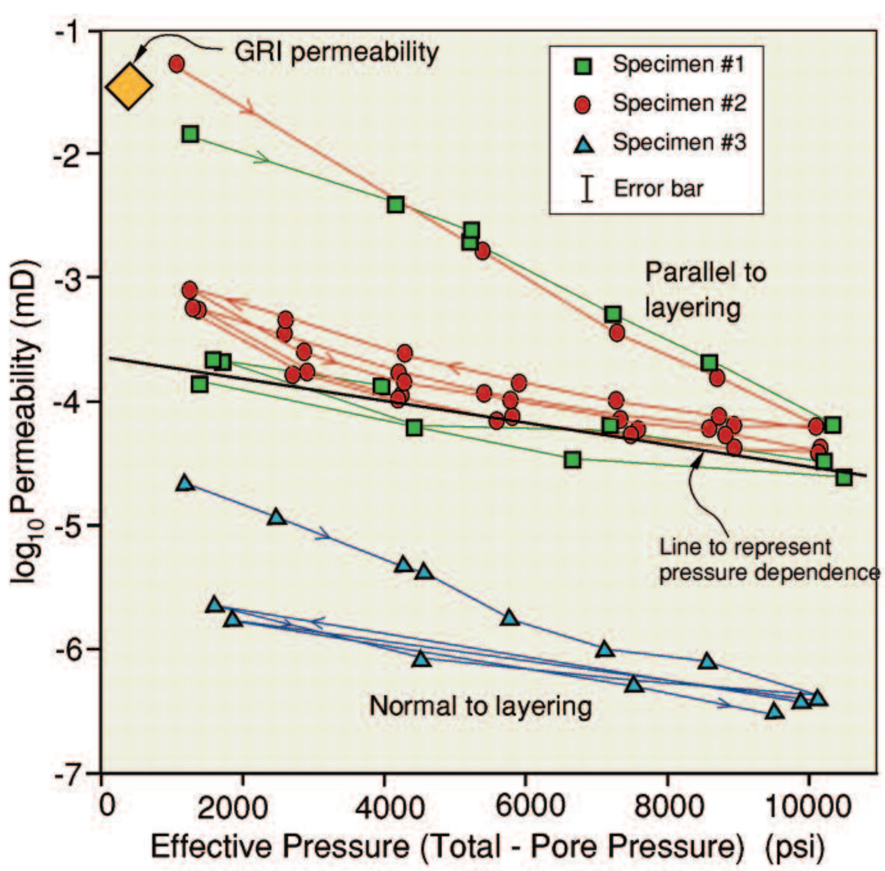

Figure 2: Experimentally determined argon gas permeability variations during repeated effective pressure cycling for Runswick Bay shale (core samples dried to constant weight at 60 °C), both parallel (2 specimens) and perpendicular (1 specimen) to layering. Permeability anisotropy is more than 2 orders of magnitude. Results are expressed as sensitivity to effective pressure (total pressure – pore pressure). Permeability decreases rapidly during the first pressure cycle, probably through microcrack closure, but the subsequent cycles show little further permanent reduction, even when the pressures are removed at the end of a cycle. The black straight line shows the function used here to represent the sensitivity of permeability to pressure for reservoir modelling purposes (based on specimen #1).

temperature fluctuations, and it is possible to measure permeability variations during progressive loading and microcrack development without interrupting the loading sequence. The method also makes it possible to determine whether the pressure cycling retains the rock in the elastic regime, or whether any permanent pore collapse has occurred.

Fig. 1 shows an example of data acquired using this method and Fig. 2 shows the gas permeability response to effective pressure cycling in the elastic regime of a typical quartz/clay-dominated Jurassic shale (collected from the intertidal zone at Runswick Bay, Yorkshire, England) of 7% porosity. Initial bedding-parallel permeability at low effective pressure is high, and would correspond to that measured by the GRI method. Increasing effective pressure for the first time provokes a rapid permeability reduction, after which further pressure cycles define a reproducible relationship between effective pressure and log permeability given by

$$\log_{10} k = -3.65 - 8.83 \times 10^{-5} p_{eff} \qquad (3)$$

in which effective pressure P_{eff} is given in psi, k is in mD. Thus the permeability decreases by about ×10 for an effective pressure change of 10000 psi, and is too large a change to be ignored in reservoir evaluation. The pore pressure is assumed to be fully effective. This is not the only possible representation of the experimental data, and is not necessarily the best, but it is the most commonly assumed form in previous literature, which is why it is used here for illustration. Fig. 2 also shows high degree of permeability anisotropy displayed by shales. Permeability along the layering is ×300 higher than across the layering. The origins of this anisotropy remain unclear.

In the transport equation (1), k is now a function of p, and this makes the equation once again non-linear. Kikani & Pedrosa[7] proposed the concept of a permeability modulus γ, by analogy with the definition of fluid compressibility;

$$\gamma = \left(\frac{1}{k}\right)\frac{\partial k}{\partial p} \qquad (4)$$

Permeability then varies exponentially with pore pressure according to

$$\frac{k(p)}{k_i} = \exp[-\gamma(p_i - p)] \qquad (5)$$

where k_i and p_i are initial values. This is a useful formulation for demonstrating the effect of stress (pressure) sensitivity in gas reservoirs (Franquet[8]). The transport equation (1) can be linearised once more using a modified definition of pseudopressure, $m'(p)$ to replace p in (1) so that it can describe the flow of a real gas through a stress-sensitive formation:

$$m'(p) = \int_{p_0}^{p} \frac{p\,k(p)}{z\mu} \mathrm{d}p \qquad (6)$$

hence

$$\nabla^2 m'(p) = \frac{\phi\mu c}{k(p)} \frac{\partial m'(p)}{\partial t} \qquad (7)$$

Influence of stress-dependent permeability on reservoir behaviour

To illustrate the effect of stress-dependent permeability on the behaviour of a gas reservoir, finite difference numerical solutions to eqn.(7) for appropriate initial and boundary conditions were obtained using program GASSIM (Lee & Wattenbarger[9]), for formation-linear flow in an infinite-acting dry gas reservoir of 100 ft thickness, at 140 °C, containing a single hydraulic fracture extending 400ft on either side of a vertical production hole. Porosity is 0.075 and initial permeability is 0.00034 mD, corresponding to eqn.(3) at zero effective pressure. Overburden pressure is 10000 psi.

Drawing down fully the gas pressure reduces the permeability by about one order of magnitude (γ = 0.00024). Fig. 3 shows how flow decreases with time for two constant downhole pressures (*Pwf* = 4000 psi and 9000 psi), more rapidly for the case of stress-dependent than stress-independent permeability. Fig.4 shows how the reduction of permeability propagates into the reservoir as the gas pressure is progressively reduced. Fig.5 shows how stress-sensitive permeability impacts on total production after 225 and 2000 days for different fixed downhole pressures. The greatest production is always at the lowest *Pwf*, but it may not be practicable to maintain this at a low value.

Well test results can appear similar in form whether formation permeability is stress-sensitive or not, but if the analysis of results does not take into account stress-sensitivity then erroneous inferences will be made of permeability, gas in place and productivity to be expected (Franquet et al. 2004). This illustration is a simple one to demonstrate the effects of stress-dependent permeability. The range of stress-sensitivities of permeability that can be displayed, how they depend upon porosity and the microstructural arrangement and elasticity of the component mineral phases in different shales, any effects of non-hydrostatic stresses, and the influence of partial liquid saturation, are issues that have barely begun to be touched upon in laboratory measurements.

Acknowledgements

Prof. R. Wattenbarger (Texas A & M University) kindly provided the code modifications to GASSIM version 6 to permit stress-sensitive reservoirs to be simulated.

References

[1] Al-Hussainy, R., Ramey, H.J., Crawford, P.B. 1966. The flow of real gases through porous media. Journal of Petroleum Technology, 237, 624-636

[2] Brace, W.F., Walsh, J.B., Frangos, W.T., 1968. Permeability of granite under high pressure. Journal of Geophysical Research, 73, 2225-236

[3] Kranz, R. L., Saltzman, J. S., Blacic, J. D., 1990. Hydraulic diffusivity measurements on laboratory rock samples using an oscillating pore pressure method, Int. J. Rock Mech. Min. Sci. Geomech. Abstr., 27, 345– 352

[4] Fischer, G. J., 1992. The determination of permeability and storage capacity: Pore pressure oscillation method. In: Fault Mechanics and Transport Properties of Rocks, edited by B. Evans and T.-F. Wong, 187– 212, Academic Press, San Diego, Calif.

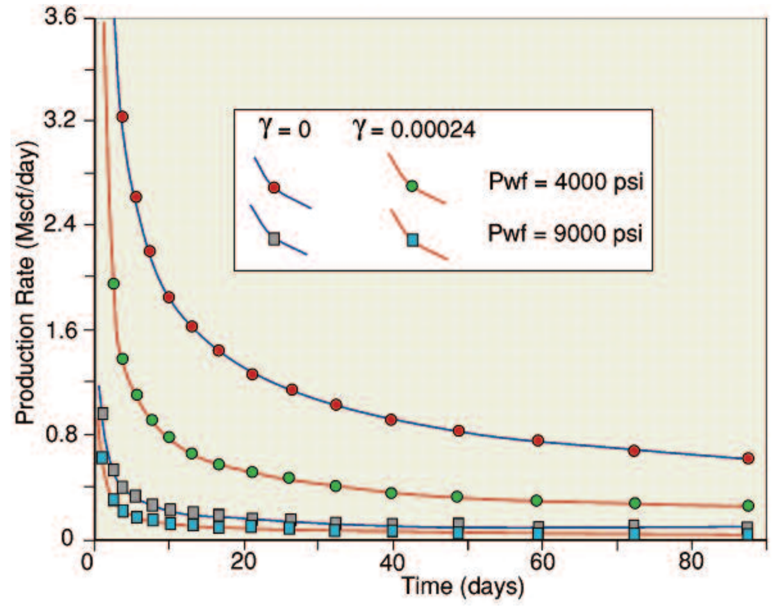

Figure 3: Comparative production rate decay with time for stress-independent (γ = 0) and stress-dependent (γ = 0.00024) reservoirs at constant bottom hole pressures (Pwf) of 4000 and 9000 psi, for an overburden pressure of 10000 psi. The effect of stress-dependence of permeability is more marked at smaller bottom hole pressure.

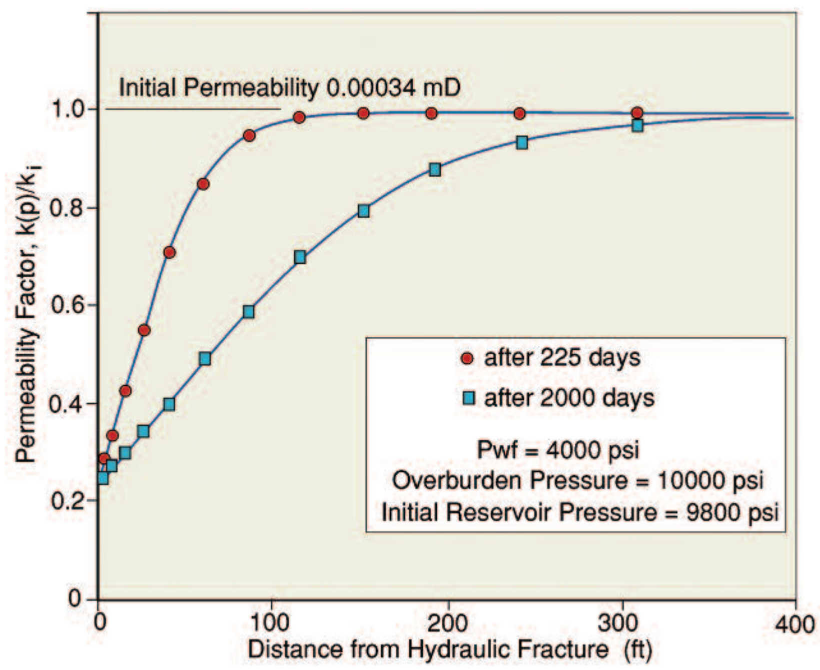

Figure 4: Variation of permeability as a fraction of the initial value k_i with distance from hydraulic fracture as a result of gas pressure drawdown in a stress-sensitive reservoir after 225 and 2000 days for a constant downhole pressure Pwf. In a stress-insensitive reservoir the permeability would remain constant at the initial value 0.00034 mD.

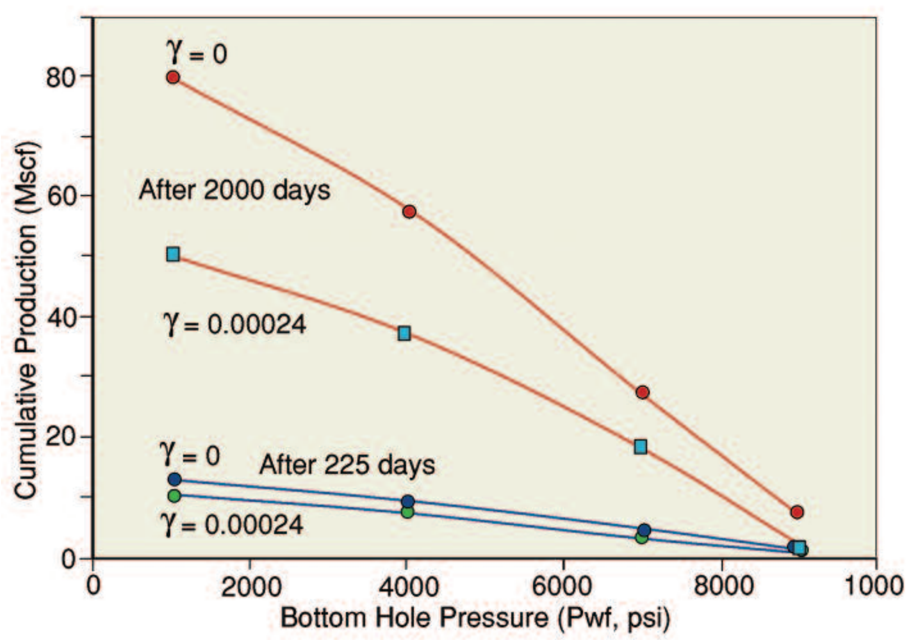

Figure 5: Illustration of the effect of stress-dependent permeability (γ = 0.00024) on cumulative production (millions standard cu. ft.) after 225 and 2000 days for a range of constant bottom hole pressures, compared to stress-insensitive reservoir (γ = 0). Overburden pressure = 10000 psi, initial gas pressure = 9800 psi.

[5] Faulkner, D. R., Rutter, E. H., 1998. The gas permeability of clay-bearing fault gouge at 20°C. Geological Society, London, Special Publications, 147, 147-156, doi:10.1144/GSL.SP.1998.147.01.10

[6] Bernabé Y., Mok, U., Evans, B., 2006. A note on the oscillating flow method for measuring rock permeability. International Journal of Rock Mechanics & Mining Sciences, 43, 311–316

[7] Kikani, J., Pedrosa, O. A., 1991. Perturbation analysis of stress-sensitive reservoirs. SPE Formation Evaluation, 379-386

[8] Franquet, M., Ibrahim, R.A., Wattenbarger, Maggard, J.B., 2004. Effect of pressure-dependent permeability in tight gas reservoirs, transient radial flow. Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum, Canadian International Petroleum Conference 2004, Calgary, Alberta, Canada, 2004 Paper 2004-089, 1-10

[9] Lee, J., Wattenbarger, R. A., 1996. Gas reservoir engineering. Society of Petroleum Engineers Textbook Series v. 5, Richardson, Texas, 349pp