# Pressure-Dependant Permeability in Shale Reservoirs Implications for Estimated Ultimate Recovery

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The bulk permeability of shale reservoirs has contributions from matrix, open natural fractures if they exist, unpropped hydraulic fractures and propped hydraulic fractures to varying degrees. In Core Lab's shale consortia permeability and/or conductivity have been measured on all of the above. These data have all demonstrated a decline to varying degrees with increasing overburden pressure, which can be a proxy for drawdown and pore pressure depletion. This has significant implications on well performance.

Permeability of shales has been measured on crushed core samples and core plugs by a variety of methods and by a variety of laboratories. The crush core permeability measurements yield true "matrix" permeability at native state saturations but with no overburden stress. The purpose of the crush permeability measurements is to make measurements without the contribution of induced micro-fractures and in cases where quality core plugs cannot be obtained. The permeability measurements on core plugs have traditionally been performed by the pulse-decay method. This method also investigates a very small volume of the plug end-face. The measurement can be made at native-state saturations and at reservoir overburden stress. However, the measurements may be erroneously high due to the presence of micro-fractures generated from stress relief of the core and gas expansion, sample acquisition, and desiccation. Recently, Core Lab's shale consortia have developed a method to measure *steady-state gas permeability* on core plugs as a function of overburden pressure. These analyses, performed on samples with no micro-fractures observed in high resolution CT scans, show a dramatic decrease in permeability as a function of stress (Figure 1). Also interesting is the hysteresis effect when the pressure is reduced after the stress ramp, indicating the reduction in permeability is permanent.

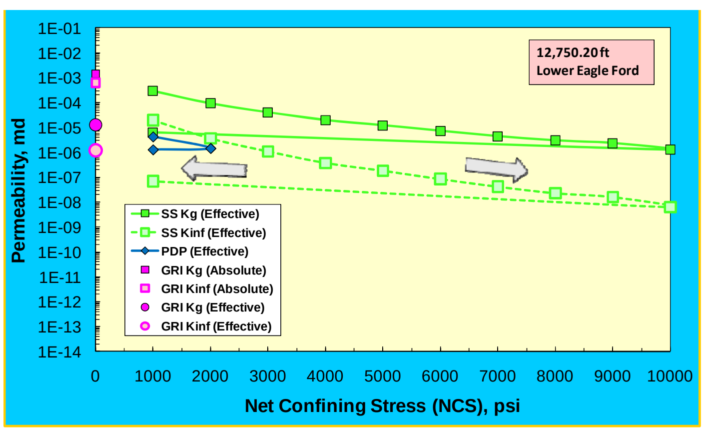


*Figure 1 – Steady-state gas permeability as a function of stress*

Shale core conductivity measurements on unpropped fractures also reveal dramatic losses in conductivity with increasing stress (Figure 2). The unpropped conductivity of a shale fracture exhibits a decline of 2 orders of magnitude, decreasing from 1000 microdarcy-ft to 10 microdarcy-ft for a stress ramp of 1000 to 6000 psi. There is a similar hysteresis effect when the pressure is reduced after the stress ramp, indicating the reduction in permeability is permanent.

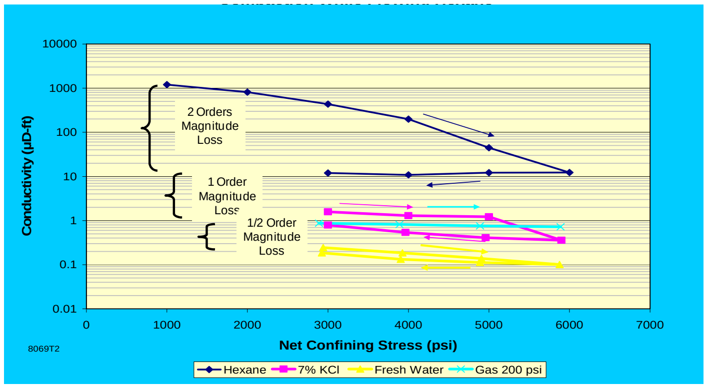


*Figure 2 – Unpropped fracture conductivity of shale as a function of stress*

Propped fracture conductivity measurements also reveal a decline in conductivity with stress (Figure 3). The decline is not as severe as in the unpropped fractures and in the matrix in terms of percent. The reduction is due to embedment and in some cases crushing of the proppant. In the case of propped fracture conductivity the values are in the millidarcy-ft range compared to the microdarcy-ft range for unpropped fractures and the nannodarcy range for the matrix.

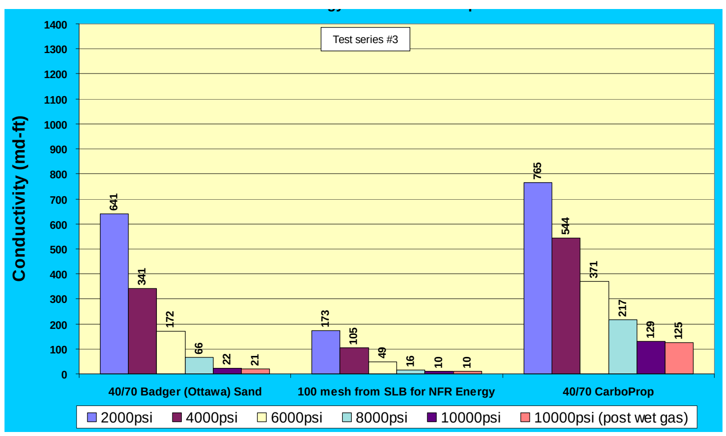


*Figure 3 – Propped fracture conductivity as a function of stress for 3 different proppants*

Bulk permeability of the reservoir can be estimated from well test production data by rate transient analysis. The values obtained are taken from the early time production data. These values are consistently higher than the core matrix values by an order of 10 to 100 times depending on the effectiveness of the stimulation. This should not be surprising given the contributions from the hydraulic fracture enhanced permeability generated in the near wellbore regions. The rate transient analysis also yields estimates of producing drainage area.

Many of the productive shale reservoirs are overpressured ranging from slightly overpressured (0.5 psi/ft) to extremely overpressured (0.9 psi/ft). This results in high pore pressure and a relatively low overburden stress. For example, a shale reservoir at 11,000 feet with a 0.9 psi/ft gradient has only about 1000 psi of net overburden pressure.

As a well is produced the drawdown has the effect of lowering the pore pressure and increasing the net effective stress on the fractures and matrix along the fractures in the near wellbore area. This results in a conductivity loss of the fractures and a reduction in the matrix permeability similar to Figures 1 to 3 above. The larger the drawdown, the faster the reduction is observed in both fracture conductivity and matrix permeability. The reduction in conductivity and matrix permeability will happen eventually during the production of the well, regardless of the drawdown. The issue is whether it occurs relatively quickly or slowly.

Currently in the industry, the measure of EUR is thought to have a relationship with the initial production rate (IP). This coupled with the fact that many operators want to report a high IP for the purposes of press releases, has led to high drawdown, rapid conductivity and matrix permeability loss, and consequently severe production decline curves. An alternative to this practice, is to limit the drawdown by holding a backpressure, thus, slowing the fracture conductivity and matrix permeability loss. This has been used in CBM to keep producing rates up because of the pressure dependency of cleat permeability.

A comparison of production decline curves for shale horizontal wells in a field is shown in Figure 4. All of these wells were of similar horizontal length and had similar stimulations. The difference between the wells is a result of productions practices. The “open rate” wells did not limit the drawdown resulting in high IP but severe decline rates. The “restricted rate” wells were choked back to minimize the drawdown and hold a backpressure. The IP of these wells is lower but the decline curves are almost flat. A comparison of the cumulative produced gas shows that the “restricted rate” wells have crossed the “open rate” wells around the 1 BCF mark. From this point forward the “restricted rate” wells have higher cumulative gas production.

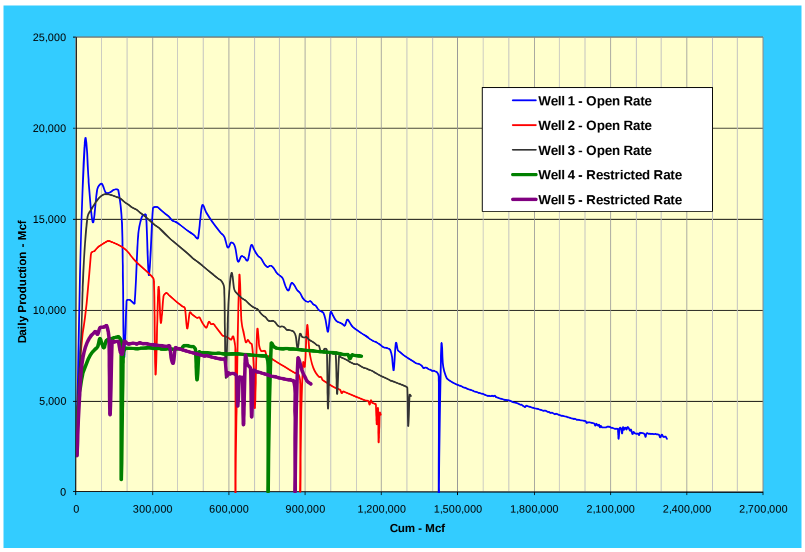


*Figure 4 – Rate vs. cumulative gas plot of “open rate” and “restricted rate” wells in a shale reservoir*

Rate transient analysis was performed on “open rate” well No.1 and the “restricted rate” well No. 4. The results are summarized in Table 1. The wells have a similar computed kh but the “restricted rate” well No. 4 has a higher fracture half length indicating a better completion. What is even more interesting is that the “restricted rate” well No. 4 has three times the drainage area compared to the “open rate” well No. 1. Decline curve analysis suggests the “restricted rate” No.4 well will have a higher EUR compared to the “open rate” well No. 1 by 2 to 3 BCF.


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| Well | Kh (md-ft) | Area (Acres) | Half Length (ft) | L/W | Days Prod |
|---|---|---|---|---|---|
| Well 1 | 16.8 | 22.5 | 522 | 10 | 356 |
| Well 4 (R) | 17.4 | 60 | 622 | 1 | 164 |

*Table 1 – Summary of Rate Transient Analysis*

Therefore, it appears that by limiting the drawdown on shale reservoirs and holding a backpressure may result in flatter decline curves, larger drainage area, and possibly higher EUR. The limited drawdown and backpressure slows the decline in fracture conductivity and matrix permeability. The backpressure "holds" the unpropped and weakly propped fractures open longer and maximizes the matrix gas feed. With all the focus on improving fracture stimulation in the industry, perhaps the way the well is produced may be just as important for maximum recovery.