Miscible Displacements with CO_2: The Importance of Total Mobility

Introduction

When CO_2 is injected into the subsurface it may displace the resident fluids either miscibly or immiscibly, often at an adverse viscosity ratio that will induce viscous fingering. In cases where CO_2 is injected into subsurface reservoirs containing oil, the displacement will be miscible when the pressure is above the MMP (minimum miscibility pressure). In reservoir simulation the fluid flow is described by a set of relative permeability (RP) curves (k_r) and the interrelated fractional flow (F_w) and total mobility (λ_T). These RPs are how measurements at the laboratory scale are upscaled to the field predictions, thus for any CCUS process in the subsurface it is imperative that these are representative of the fluid flow in question in order to give accurate predictions of stored CO_2 volumes and understand migration pathways that could lead to incorrectly estimated leakage risks.

It is commonly stated in the literature that the transition from immiscible to miscible CO_2 displacements can be described by a shift in the relative permeability function from their immiscible form to a set of straight line functions (Alzayer et al. 2018; Masalmeh et al. 2025). Here we present an analogy between miscible and immiscible flow, discuss the meaning of straight line RPs, and highlight the importance of the viscosity mixing profile on unstable miscible displacements.

Method/Theory

First, following the approach of Lantz (1970), we draw parallels between miscible (e.g. solvent (CO_2) /oil) and immiscible (e.g. solvent and water) flow by considering how a fully miscible displacement can be modeled using a pseudo-immiscible approach. In the miscible case, we have a viscosity mixing curve $\mu(C_s)$ with end point viscosities of μ_s and μ_o for the solvent and oil, respectively. This can then be modeled as a pseudo "two-phase" system of fixed phase viscosity where the pseudo relative permeabilities - $k_{rs}(C_s)$ and $k_{ro}(C_s)$ – are then dependent upon "saturation", equivalent to C_s. Note that capillary pressure is taken as P_c=0 here i.e. the system is viscous dominated. Thus, the two phase Darcy law for each pseudo phase is:

$$v_s = -\frac{k.k_{rs}(C_s)}{\mu_s}\left(\frac{\partial p}{\partial x}\right) \quad (1)$$

$$v_o = -\frac{k.k_{ro}(C_s)}{\mu_o}\left(\frac{\partial p}{\partial x}\right) \quad (2)$$

This can be re-arranged to give the total Darcy velocity:

$$v_T = v_s + v_o = -k\left(\frac{k_{rs}(C_s)}{\mu_s} + \frac{k_{ro}(C_s)}{\mu_o}\right)\left(\frac{\partial p}{\partial x}\right) \quad (3)$$

where the total mobility function of the two phase system is:

$$\lambda_T(C_s) = \left(\frac{k_{rs}(C_s)}{\mu_s} + \frac{k_{ro}(C_s)}{\mu_o}\right) \quad (4)$$

Contrasted with the completely miscible case:

$$v_T = -k\left(\frac{1}{\mu(C)}\right)\left(\frac{\partial p}{\partial x}\right) \quad 5$$

And so we have the immediate correspondence between the miscible and pseudo-immiscible forms of the total mobility function, $\lambda_T(C_s)$:

$$\lambda_T(C_s) = \frac{1}{\mu(C_s)} = \left(\frac{k_{rs}(C_s)}{\mu_s} + \frac{k_{ro}(C_s)}{\mu_o}\right) \quad 6$$

Secondly, the fractional flow for a fully miscible displacement *must* be a straight line, whatever the viscosities of the solvent and oil; i.e. the fractional flow must be equivalent to the local concentration by definition:

$$f_s(C_s) = \frac{1}{1+\left(\frac{k_{ro}(C_s)}{k_{rs}(C_s)}.\frac{\mu_s}{\mu_o}\right)} = C_s \quad 7$$

Thus, we have two constraints on our pseudo miscible system: any solution must honor both Eq. 6 and 7. Following this, these equations can be re-arranged to give the following relative permeability functions (Lantz 1970):

$$k_{rs}(C_s) = \frac{\mu_s.C_s}{\mu(C_s)} \quad 8$$

$$k_{ro}(C_s) = \frac{\mu_o.(1-C_s)}{\mu(C_s)} \quad 9$$

Take the example of a fully miscible displacement where the solvent (CO_2), μ_s=0.05 mPa.s, displaces oil, μ_o=0.50 mPa.s with a viscosity mixing curve ($\mu(C_s)$) described by a power law with N=5, Figure 1.

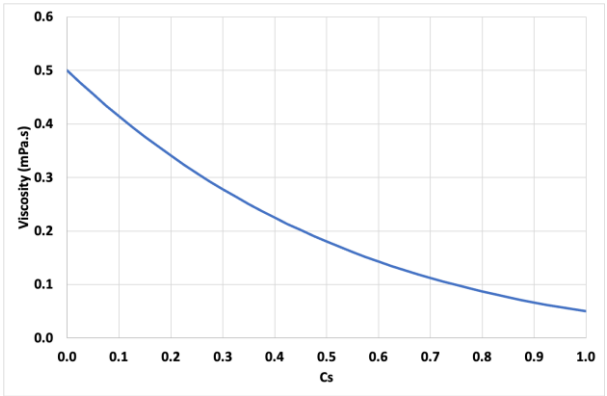

Figure 1 Viscosity mixing curve of two fully miscible fluids following a power law mixing rule with N=5. μ_s=0.05 mPa.s and μ_o=0.50 mPa.s.

Following the methodology from Lantz (1970), this curve can be used to generate two pseudo-miscible relative permeability curves which honor the viscosity mixing curve and have a straight line fractional flow. Figure 2 shows these curves and compares them against a set of straight line relative permeabilities. Note, in the case of straight line relative permeability curves, the viscosity mixing rule and fractional flow are calculated *from* the relative permeability curves.

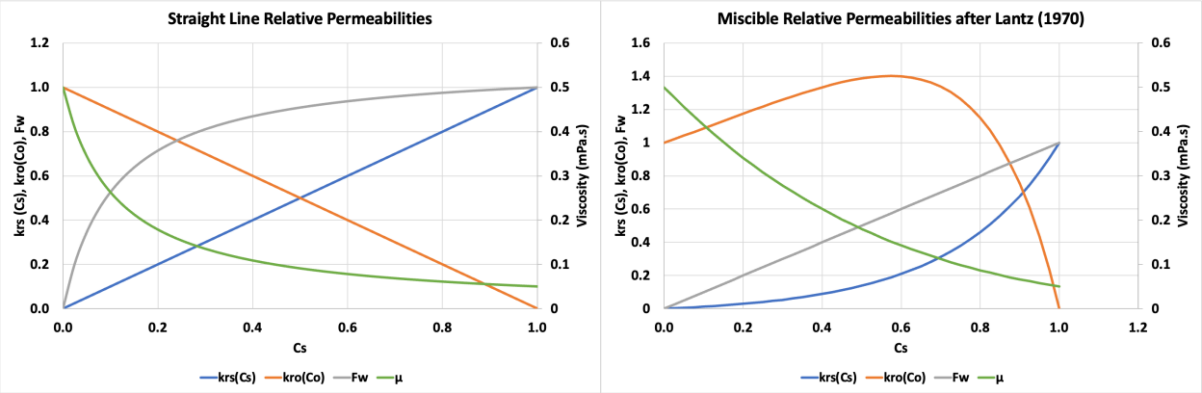

Figure 2 Relative permeabilities and corresponding fractional flow and viscosity defined by straight line (left) and Lantz (right) functions

It is immediately apparent that the straight line relative permeability curves will not give an appropriate result when used in black oil simulations. The viscosity mixing curve does not represent the form we know it must have, and the fractional flow is not a straight line. Given the form of the fractional flow curve, there is not a shock front – i.e. a Welge tangent intercepts at $k_{rs}=0$ – instead a low saturation diffuse front will propagate rapidly through the system. In contrast, by following the methodology proposed by Lantz (1970) the viscosity mixing curve is reproduced (as the RPs were calculated from this) and the fractional flow is a straight line. This methodology does result in non-monotonic forms of the relative permeability curves, which require a simulator capable of handling them such as Eclipse. This is where the distinction between a black oil simulation and a compositional simulation is important. When full miscibility is achieved in compositional simulation, both the CO_2 and oil are treated as the same phase. In such cases a straight line relative permeability *would* be appropriate as the "phases" have the same viscosity. In practice however, at this point in the simulation the relative permeabilities are not used i.e. any relative permeability function would give the same result. Here only the viscosity mixing profile (μ(C)) is used i.e. the displacement is controlled by λ_T.

While it is common to use correlations to predict the mixture viscosity, it is critical that these correlations are accurate as, for a given system (k, φ, D), a miscible displacement is governed only by μ(C) – shown directly in Beteta and Sorbie (2026). A series of calculations are presented where the viscosity contrast between the two fluids is kept constant, but the λ_T profile between the fluids is varied by changing the exponent in the power law used to describe μ(C). A random correlated permeability field is used with an average permeability of 2.3 D and a dimensionless correlation length of 0.02. Porosity is constant at 0.33.

Results

The displacement patterns for a range of miscible calculations using varied power law exponents – i.e. varied λ_T – and cases with the same λ_T modelled as fully miscible, pseudo-miscible, and straight line RPs are shown in *Figure 3*.

Firstly, it is clear that the miscible and pseudo-miscible simulations are *identical*. This gives credence to our hypothesis that λ_T provides a direct correspondence between miscible and immiscible flow. Secondly, it is demonstrated that λ_T controls the extent of finger formation. When the λ_T is highest, N=5, the fingers are more developed and breakthrough earlier. Where low λ_T, N=0.25, suppresses finger formation and delays breakthrough. Naturally, employing straight line relative permeability functions in the black oil simulation does not capture any detail of the miscible displacement.

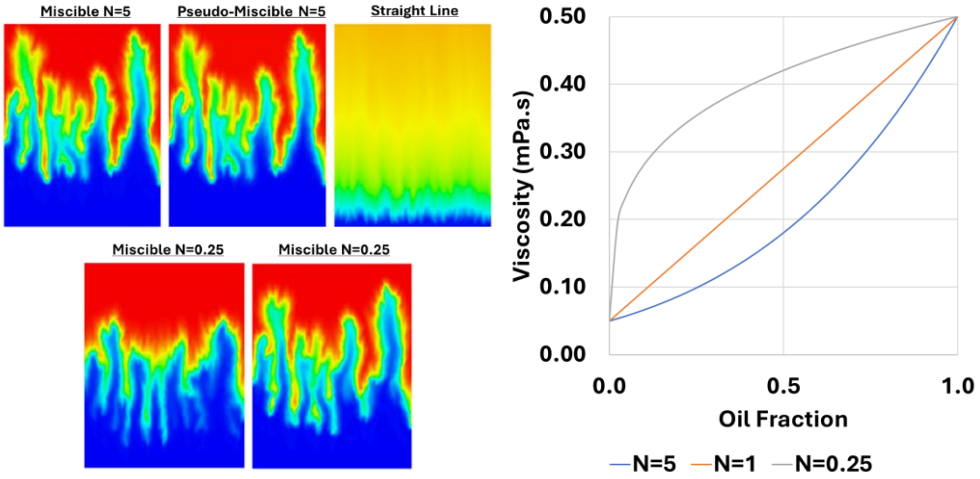

Figure 3 Local solvent (CO_2) concentration at 0.53 PV of injection for black oil and miscible simulations. Viscosity mixing profiles on right

Conclusions

It has been demonstrated that during miscible displacements involving CO_2 that the total mobility function (λ_T, the inverse of the viscosity profile $\mu(C)$) controls the *extent* of viscous fingering observed. That is to say, at a given viscosity ratio, e.g. $\mu_o/\mu_{CO2} = 10$, while fingering can occur the finger growth is controlled through λ_T. This observation is critical for evaluating the migration path, storage volume, and oil recovery potential when considering displacement of oil by CO_2 in the subsurface. We also demonstrate that λ_T gives a direct equivalence between miscible and immiscible displacements. This underpins our previous research on the modelling of ***immiscible*** viscous fingering through a fractional flow approach that seeks to maximize the total mobility (Sorbie et al. 2020). A fuller discussion of total mobility, viscosity mixing profiles and the analogy between miscible and immiscible displacements, including experimental evidence, is given in Beteta and Sorbie (2026).

As a point of future work, this leaves the question on the form of the relative permeabilities under *near-miscible* conditions. Under these conditions, it is commonly observed that relative permeabilities *approach* straight lines. In a compositional simulation description of the immiscible → miscible transition, the 2 phases are becoming identical and thus have the same viscosity; therefore, Eqs. 8 and 9 predict straight line RP functions. However, if the system is already fully first contact miscible, the and two fluids have different viscosities, then the pseudo-two phase RP functions are certainly not straight lines.

References

Alzayer, A.N., Voskov, D.V., Tchelepi, H.A.: Relative Permeability of Near-Miscible Fluids in Compositional Simulators. *Transport in Porous Media* **122**(3), 547-573 (2018). https://doi.org/10.1007/s11242-017-0950-9

Beteta, A., Sorbie, K.S.: The Role of the Total Mobility Profile in Miscible Viscous Fingering and its Significance in Immiscible Fingering. *Under Review* (2026).

Lantz, R.B.: Rigorous Calculation of Miscible Displacement Using Immiscible Reservoir Simulators. *SPE Journal* **10**(2), 192-202 (1970). SPE-2594. https://doi.org/10.2118/2594-PA

Masalmeh, S., Farzaneh, A., Sohrabi, M.: Gas/CO2 Mobility under 2-Phase and 3-Phase Flow in Carbonate for CO2-EOR and CCS Projects. Presented at the 23rd EAGE European IOR+ Symposium, Edinburgh, UK, 2-4 October, 2025. https://doi.org/10.3997/2214-4609.202531034

Sorbie, K.S., Al Ghafri, A.Y., Skauge, A., Mackay, E.J.: On the Modelling of Immiscible Viscous Fingering in Two - Phase Flow in Porous Media. *Transport in Porous Media* **135**, 331-359 (2020). https://doi.org/10.1007/s11242-020-01479-w