Fracture relative permeability revisited

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Relative permeability is one of the most uncertain terms in multiphase flow through porous media. Therefore, such a basic parameter must be well understood to provide confidence in reservoir simulations.

In a fractured reservoir, evaluation of relative permeability curves is complicated due to the nature of double porosity systems, where fractures develop a discontinuity in multiphase flow between adjacent matrix blocks. Fracture relative permeability is examined here with corresponding effects on fractured reservoir performance.

OCCURRENCE OF NATURAL FRACTURES

Studies have shown that 60% of the world’s remaining oil reserves reside in fractured formations. Natural fracture is defined as macroscopic planer discontinuity within reservoir rocks with positive or negative effect on multiphase fluid flow within the reservoir. Virtually all reservoirs can contain at least some natural fractures. However, from a geological and reservoir engineering point of view, a reservoir can be classified as naturally fractured only when the fractures have an effect, either positive or negative, on fluid flow within the reservoirs.

In naturally fractured reservoirs (NFRs), the matrix that contains most of the oil is surrounded by a system of fractures of very little volume but with permeabilities that are several orders of magnitude higher than that of the matrix (not for all type of fractured reservoirs, but for Type II, as defined in Table 1, which is encountered frequently in the south of Iran).

<table>
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<th>NFR Type</th>
<th>Definition</th>
<th>Examples</th>
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<td>Type I</td>
<td>Fractures provide essential porosity and permeability</td>
<td>Anal, Libya; Edison, California</td>
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<tr>
<td>Type II</td>
<td>Fractures provide essential permeability</td>
<td>Agha Jari, Iran; Haft Kel, Iran; Spraberry trend area, Texas</td>
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<tr>
<td>Type III</td>
<td>Fractures provide permeability assistance</td>
<td>Kirkuk, Iraq; Dukhan, Qatar</td>
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Fluid flow in fractured porous media is described by either explicitly or implicitly accounting for discrete fractures. The most popular models for such descriptions are dual continuum, discrete fracture network and “stacked block model or multi-sector.” Fracture relative permeability (FRP), as a critical parameter, is available within structure of all these models.

As common practice, straight-line relative permeabilities are used for fractures during simulation of NFRs without a clear understanding about their accuracy. Using straight-line relative permeabilities in fractures can cause significant error (70%) in water/oil systems, while underestimating oil production times in some gas/oil systems can cause an error by a factor as much as three.

**FRACTURE RELATIVE PERMEABILITY**

During multiphase flow in porous media, the relative permeability of a phase is a dimensionless measure of the effective permeability of that phase and therefore can be viewed as an adaptation of Darcy’s Law to multiphase flow. The relative permeability functions resulting from multiphase flow in fractures have received less attention than those in porous media.

One study proposes straight line (X-Curve) relative permeability, which is a default selection for fractures during numerical simulation of NFR (the sum of relative permeabilities is one). The study also noted that X-Curve is not applicable for fractured media where a system of interconnected fractures is present. Later, another study confirmed that FRP is not generally a linear function of saturation (based on some video imaging and image processing).

According to a study from 1990, FRP may depend on the nature and spatial correlation between apertures. The sum of relative permeabilities within fracture can be considerably less than one at intermediate saturations. The predicted range of saturation values at which neither phase can flow at all (phase interference phenomena), but the theory neglected the possibility of “blobs” of one phase conveyed by the other.

There are some critical questions that can’t be covered with X-Curve FRP. For example, if drops of a non-wetting phase come from the matrix in the fracture filled by wetting phase, what is flowing condition of these drops (during water flooding of water-wet matrix) and what is behavior of those drops in horizontal fractures when compared with vertical ones? It is obvious that miscible multiphase flow within the fracture network makes these issues more complex.

A study from 1982 stated that water relative permeability in porous media only depends on mobile water saturation and oil relative permeability is a function of oil saturation and the range of pore sizes that contain oil saturation. These statements have conflicted with X-Curve relative permeability within a fractured network. Pore space of a fracture differs from the pore network of rock matrix in two important ways. First, a fracture is a two-dimensional network of apertures and constrictions, and capillary forces are much weaker in the pore space of most fractures than in rock (matrix blocks). Percolation theory forbids simultaneous multiphase flow in a single fracture if flow is dominated by capillary forces, with some exceptions:

1. Larger viscous force in compare to capillary force
2. Gravity segregation within non-horizontal fracture
3. Film flow of wetting phase along fracture walls during non-wetting phase flow from fracture interior
4. Multiphase flow though a network of fractures
5. Periodic flow due to saturation fluctuation.

The case has also been made for a percolation model for two-phase flow in a single fracture that explicitly considers gravity segregation by a dimensionless parameter HD as follows:
According to this study from 1994, FRP curves tend to straighten with HD increase that can be linked to fracture capillary pressure. This parameter only accounts for gravity segregation effect (with corresponding relative permeability curves in Fig. 1) but was used as surrogate variable for any of the effects that shift relative permeability curves between the straight-line form and the capillary dominated limit. Therefore, Fig. 1, as different probable fracture relative permeability trends, should be used carefully during simulation of a naturally fractured reservoir.

NEW LOOK TO RELATIVE PERMEABILITY

Within this section, several simple facts are comingled together to produce a general statement about fracture relative permeability. At first, it is assumed that Darcy's Law is applicable for fluid flow within fracture network. One 2004 study on modeling fluid flow inferred that beyond an aperture size of approximately 0.06 mm, the effects of fracture roughness or tortuosity will be insignificant that confirm this assumption.

One theory proposes that for fracture aperture higher than 0.05 mm, capillary continuity between a stack of blocks cannot be realized, which can be treated as minimum required fracture width to detect fracture as distinguished discontinuity between two matrixes. Also, reported fracture porosity within NFR located in the Middle East (less than 0.1% rock volume) and matrix dimensions (10–15 m) means that fracture width can vary between 3 and 4 mm.

Zonation of fractured reservoir base on relative saturation of matrix blocks/fractures (Fig. 2) is another important issue with direct effect on FRP. In a fractured reservoir the two-phase contact is sharp and horizontal in static or dynamic conditions since the transmissibility in a fractured network is high due to large permeability of fractures (Type II of NFR) and any change in level is rapidly re-equilibrated.
In this basis and by neglecting irreducible saturation, it can be assumed that only one phase is available within each fracture (horizontal or vertical) during static conditions. But dynamic condition of a given NFR should be treated carefully. As production starts within a given NFR, depletion of oil zone and consequent expansion of the gas cap and aquifer will modify gas-oil and water-oil contact within the fracture network. Therefore, fluid extracted from matrix blocks will be flashed into surrounding fractures first and then each phase will start to flow within the fracture network such as film, bubble or droplet.

When liquid droplets or gas bubbles are flowing through a fracture surrounded by another fluid (what happens in gassing and gas-invaded zone of NFR), they usually flow under their buoyancy forces (gravity segregation). Therefore, Fig. 1 and Eq. 1 can be used to predict local FRP. Reported data from NFR in Middle East reservoirs indicate that near the X-Curve, relative permeability can be used in this condition. An alternative approach indicates that a near-miscible relative permeability curve approach to the X-Curve for high capillary number.

One study found that there is a limiting capillary number (around 20) which abruptly changes the effect of FRP on oil recovery. On this basis, FRP is important for low capillary numbers when viscous forces are significant and two-phase flow exists in the fracture. At high capillary, however, a number of most of the two-phase flow occurs inside the matrix block and the effect of FRP is reduced. In these cases X-Curve FRP can be used without significant error in simulation performance, which is consistent with FRP response to HD increase.

At the same time the fracture may happen to have a continuous strip of oil or water flowing through it under buoyancy or film flow condition (localized continuous flow path which are periodically blocked and unblocked by other phases or film flow in proportion to their average saturation). This is probable in water zone and water invaded zone of a given NFR.

A major issue in these cases is that gravity segregation is not possible within fracture as a consequence for wettability effects, low fluid density difference and high interfacial tension between phases. Therefore, the parameter of Eq. 1 cannot be used as a decision making tool for FRP trend.

Analytical models for immiscible flow within capillary tubes (non-X-Curve models) are therefore recommended for these cases (water-oil flow in fractures) with some irreducible saturation for water and...
oil (which is zero for X-Curve model). The following correlation has been proposed for an water-oil system as the best fit to experimental data\(^{14}\) ($\lambda$ is pore size distribution index).

\[ k_{rw} = k_{rw}^* \left( S_w' \right)^{2+\lambda} \]

Eq. 2

\[ S_w^* = \frac{S_w - S_{wfr}}{1 - S_{wfr}} \]

Eq. 3

\[ k_{rw} = k_{rw}^8 \left( 1 - S_w' \right)^2 \left[ 1 - \left( S_w' \right)^{2+\lambda} \right] \]

Eq. 4

\[ k_{rw} = k_{rw}^* \left( S_w' \right)^{2+\lambda} \]

Eq. 5

Despite all theoretical, experimental and numerical efforts, the physics of multiphase fluid flow through fractures is still poorly understood. But all of the various approaches should consider the nature of NFR during development of any model for FRP. As an example for a given NFR with 100,000 STBD, oil productions that contain 2 million matrix blocks (with an average height of 4 m), each matrix block (as average) should deliver only 5 cc oil as average per minute. Therefore, dynamic behavior of such a reservoir is far from conventional fractured core setups.

CONCLUSION

Major FRP theories and applications within NFR have been investigated here and checked with actual multiphase flow within NFR. It can be concluded that a universal curve, e.g. X-Curve, is not a good option for fracture network behavior during NFR simulation. As a result, it is recommended to use the X-Curve theory for gas-oil system FRP (e.g. gas invaded zone in NFR) and some analytical model proposed as FRP for locations such as water-invaded zones. This finding may differ with some experimental data but, as mentioned with some examples, behavior of actual fractured reservoirs is far from conventional core setups, which is in direct conflict with scale-up principles.

As a next step in this research, a general correlation is under development based on different dimensionless numbers (e.g. bond number, capillary number) to predict FRP.

LITERATURE CITED


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