Discussion of Capillary Pressure in Fractured Porous Media

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In "Capillary Pressure in Fractured Porous Media" (June 1990 *JPT*, Pages 784-91), Firoozabadi and Hauge report interesting experiments showing the effect of different contacting media on continuity between two similar rocks. They showed that a better continuity develops when the contacting interface has a similar grain size than when the grains are coarser. They also reported simulated results of three 1-ft [0.3-m] blocks with different fracture arrangements and a series of centrifuge experiments of smaller cores stacked in various forms. They assumed the blocks or the cores to be discontinuous and used fracture capillary pressure, P_{cf}, and fracture relative permeability, k_{rof}, without experimentally verifying them, to calculate stack drainage. They simulated approximately the overall recovery from the blocks without matching the liquid distribution of the upper blocks.

The purpose of this discussion is (1) to demonstrate that Firoozabadi and Hauge's calculated P_{cf} is incorrect; (2) to discuss why they were not able to match the fluid saturation in different blocks and therefore why the $P_{cf}-k_{rof}$ approach is not applicable in solving capillary continuity between blocks; and (3) to show how to use the constriction concept[1-3] to history match a correct fluid distribution in different blocks in one of the experiments.

As liquid flows from an upper to a lower block, the vertical permeability of 0.007-in. [0.18-mm] -diameter spheres with cubic packing, as shown in Firoozabadi and Hauge's Fig. 5, exceeds 200 darcies and is not in the 10-to-20-darcy range. The theoretical drainage threshold pressure, $P_{cf}=2\sigma/r$ ($\theta=0$), where r is the effective radius of the moving interface through a layer of 0.007-in. [0.18-mm] -diameter spheres with cubic packing between parallel planes (their Fig. 5) saturated with an oil of $\sigma=24$ dynes/cm [24 mN/m], is about 0.1 psi [0.69 kPa], not 0 psi [0 kPa], when gas enters from the side face. Firoozabadi and Hauge ignored the fact that the P_c of a sample saturated by a nonwetting phase has a different irreducible saturation and shape than when it is saturated by the wetting phase. The former P_c has more of an L-shape than the latter. Therefore, their Eq. 4 has to be corrected for such differences because the Berea sandstone is water-wet. After the fractures are invaded, oil flows vertically with a very low oil saturation. Therefore, the imbibition P_{cf}, which is the mean pressure difference across the moving oil interface flowing out from the matrix pores and the gas phase in the fracture with a much smaller value than the drainage P_{cf} for the same saturation, is applicable, not the drainage P_{cf}. Firoozabadi and Hauge used pressure difference across the stagnant gas/oil interface between the grain boundaries to calculate P_{cf}. In the absence of a horizontal fracture pressure gradient, it is also not clear how they were able to use a P_{cf} of up to 1 psi [6.9 kPa]. When the maximum fracture pressure difference $\Delta\rho gh$ is about 0.3 psi [2.07 kPa]. Therefore, the fracture P_{cf}, k_{rof}, and k_f used in their calculations are not well founded.

To demonstrate why they calculated much less recovery from the top and much more from the middle block, it is first necessary to demonstrate how simulators treat P_c and P_{cf}. Introducing fracture capillary pressure reduces the effect of matrix P_c by nearly the maximum P_{cf} value (**Fig. D-1**) because oil saturation in the fracture between draining blocks drops to a very small value as the drainage rate from the blocks is reduced. At this point, I should mention that the duration of maximum drainage rate was less than 10 hours for Experiment 2 and about 1 hour for Experiment 4 during which the fracture oil saturation remained high. This is in contrast with Firoozabadi and Hauge's simulated fracture liquid saturation of 0.71 after 32 hours where the drainage rate from the blocks dropped to less than one-third its maximum value. This was achieved by assigning fracture P_{cf} and k_{rof} and using a fracture permeability of 10 darcies rather than 200 darcies.

As may be noted from Fig. D-1, the P_c of the upper two blocks should be reduced considerably because the major portion of each matrix block is within the capillary holdup and the top block produces nearly down to the residual. This is why $P_c>1.0$ psi [6.9 kPa] is necessary to displace the top matrix P_c to a reasonable value for Experiments 2 and 4. However, as shown in Fig. D-1a, after the matrix P_c is displaced to a sizable breakthrough, much more P_{cf} is required to displace the P_c further to have the correct residual oil in the top block. In other words, if P_{cf} were increased to 2 psi [13.8 kPa], for example, the upper block could have produced a volume closer to the actual, but the middle block would have produced proportionally more, which means going in the wrong direction. Therefore, there is a P_{cf} that makes the excess calculated recovery from the middle block compensate for the lower calculated recovery from the top block. Thus, it is obvious that these experiments cannot be simulated properly by varying the above arbitrary parameters and require a different approach.

The following unpublished experiment further demonstrates that the above approach cannot be used to match even the overall history. Several gravity-drainage experiments were made under an NIOC/Shell joint research project in Rijswijk (1975-78) on different cores. Time/recovery of each core was first measured for a specified gas/liquid system. The cores, one of which was divided diagonally into two parts, were then fractured by applying vertical stress. This inclined fracture plane extended from approximately midheight to just above the bottom of the cylindrical core. This fractured core, among others, was resaturated and allowed to drain, similar to the unfractured-core experiments. The fractured core produced a maximum of 2% less than the unfractured experiment during the first 15% of drainage time. This difference was reduced to about 0.1% toward the end of drainage time. The experiment showed nearly full continuity between the two pieces, the upper piece having nearly the entire initial height. If Firoozabadi and Hauge simulate the behavior of such an experiment using any hypothetical data and a P_{cf} similar to any of those used in their experiments, they will find a final recovery much higher than the measured value, because the upper piece will reach its maximum recovery with $P_{cf}=0$. Therefore, the problem of partial or full continuity between blocks could not be solved correctly by the $P_{cf}-k_{rof}$ approach.

During the maximum drainage rate, an excess continuity through liquid bridges can

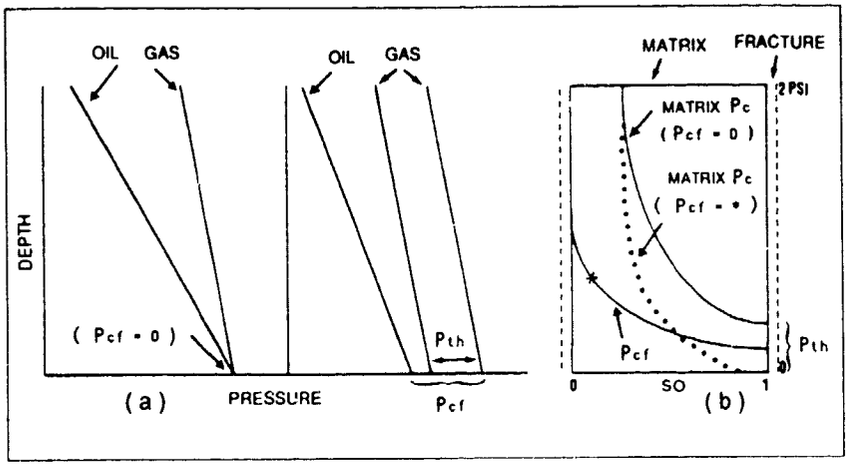

Fig. D-1—Effect of fracture capillary pressure, P_{cf}, on the initial potentials acting on (a) a draining block and on (b) Matrix P_c.

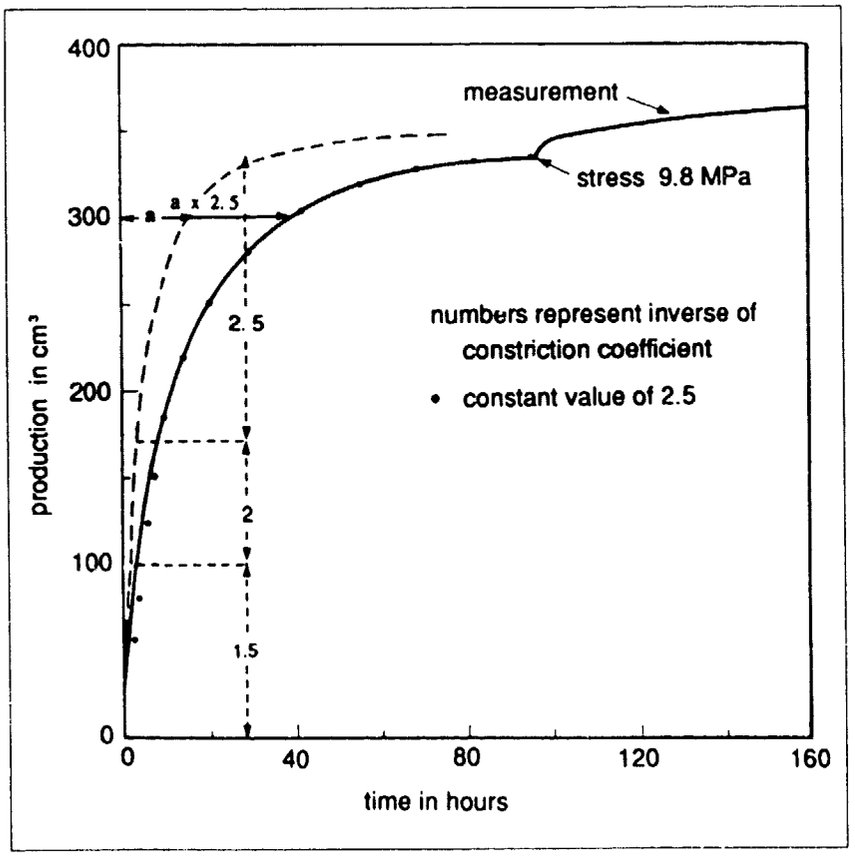

Fig. D-2—Measured and matched recovery vs. time (Case 2 experiment).

exist between blocks that disappears as the drainage rate from the blocks drops. Thereafter, continuity between blocks remains through more permanent liquid contacts covering the surface of the solids in contact between the blocks. Continuity resulting from the liquid bridge is a function mainly of fracture aperture and the size of liquid droplets falling from the upper blocks, which is a function of interfacial tension. Continuity through permanent liquid over solid contacts is a function of the ratio of the average contact area to the average area between the contacts and the ratio of the matrix holdup height to one-half the average distance between the contact points.[1,2]

As may be noted, the contact area developed through liquid bridges and liquid covering the solid contacts is not physically measurable by a direct method. However, because the constriction factor is equivalent to the effective permeability over the matrix permeability, its value can be calculated by history matching the recovery curve. This was done for Experiment 2 using $k_{ro} = S^{3.5}$, where S is the normalized oil saturation with an $S_{or} = 0.35$. A simple matrix P_c with a constant threshold height of 0.567 psi [3.91 kPa] was found to give as good a result as a more complex P_c function and the analytical equation given previously.[1,2]

With Firoozabadi and Hauge's fluid and rock data, recovery with complete continuity between the blocks was calculated and is given in **Fig. D-2.** The Experiment 2 recovery curve was then matched perfectly by calculating the constriction factor or the effective permeability ratio. This factor is 0.666 during the first 3 hours, reduces to 0.5 from about 3 to 7 hours (transition), and stays at 0.4 until 96 hours. The main reason for using a larger, earlier constriction coefficient is the presence of liquid bridges, as discussed earlier. The measured recovery curve is therefore constructed by multiplying the time scale of the calculated curve by the inverse constriction coefficient.

The measured recoveries after 196 hours and after applying stress on the blocks were 0.581 (top) and 0.151 + 0.042 = 0.193 (middle and bottom). The calculated values after 196 hours without stress are 0.577 and 0.188 for the top and the two lower blocks, respectively, which are extremely close to the actual values. Firoozabadi and Hauge's simulated recovery from the top block after 96 hours is 0.581 − 0.406 = 0.175 lower and that from the middle block is 0.29 − 0.151 = 0.139 higher than the measured values after 196 hours. A much larger recovery difference should be seen in the middle block if the authors extend their simulated recovery to 196 hours. They noted the above major differences in their simulated examples; however, instead of reconsidering the possible problem in their approach, they concluded that the difference is caused by an unknown mechanism.

Their Arrangements 2 and 3 of centrifuge experiments show nearly a full continuity between the cores when they are corrected for the difference in their total length. That is, recovery histories can be simply reproduced, with a correct fluid distribution, by considering each stack as one continuous block, rather than using arbitrary P_{cf} and k_{rof}. For example, Firoozabadi and Hauge used a drainage P_{cf} of 40 psi [276 kPa] while the maximum oil/air pressure difference in the bottom fracture is about 11.5 psi [79.3 kPa]. Note that (1) Arrangement 2 of both cases with $k = 1.8$ md gave almost exactly the same recovery history as Arrangement 1 with $k = 3.1$ md; (2) the bottom core of Arrangements 2 ($k = 1.8$ md) and 4 ($k = 3.1$ md) with only 0.09 cm difference in length gave the same recovery at the end of the experiment; and (3) the 3.27-cm core in Arrangement 4 has a much better P_c than the 3.17-cm core because it produced 8.4% more than the latter under the same conditions when a threshold of 1.4 cm is deducted from each sample. It therefore shows that the cores used in these experiments are extremely heterogeneous and that the 6.5% recovery difference between the two Arrangements 4 is caused mainly by the 9% extra length of Case 1 and changing of the position of the top core in Case 1 to the bottom core in Case 2. From the above facts,

it would not be appropriate to use the recovery difference of Arrangements 4 to draw any conclusions.

It appears[4] that the main cause of block-to-block interaction is still not clear. The confusion arises from accidentally calculating a correct result when simulating a stack of blocks with horizontal fractures. This results because there is no choice regarding draining liquid into a horizontal fracture, with no horizontal pressure gradient, except to flow through the lower block when the rate is less than the maximum rate. Experiments[1] show that the same process exists when liquid is poured over a tilted fracture associated with a fully saturated block[5] because the draining liquid develops a film over the block surface, which is surrounded by gas. As long as the liquid film is covered by gas phase surrounding the block, the liquid film is forced to flow through the contacting matrix. The driving force (Fig. D-1) is the higher gas pressure than oil pressure when the block is fully liquid-saturated. When the matrix gas/oil contact is advancing, the gas/liquid pressure difference decreases while the imbibition capillary pressure becomes active. To simulate this process, one must subgrid the tilted fracture thickness so that liquid flows rapidly to the fracture grid in contact with the matrix. Because the pressure gradient in the vertical direction is larger than that along the tilted fracture and the average film length covering the blocks is much larger than its thickness, the liquid film flows through the matrix rather than the tilted fracture. The liquid infiltration into a block owing to gas/oil pressure difference and/or capillary pressure is discussed in Ref. 1 (Page 637)

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