Your Rocks And Jimmy Neutron

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One of the major problems that production geologists and reservoir engineers encounter is establishing a good relationship between porosity and permeability. Much of the science of reservoir characterisation is devoted to understanding the relationship between porosity and permeability in one's reservoir rocks. This understanding is commonly derived from a study of reservoir core samples.

Many techniques are available for evaluation of reservoir core samples, but relatively few can provide a full image of the internal structure of the core while also providing porosity, permeability and fluid saturation information. A new technique to image core samples, using neutrons, has been developed by workers at the Centre of Excellence in Petroleum Geology (CEPG) at Curtin University. Neutron image analysis has an advantage over X-ray CT and NMR techniques in that it can directly image the presence of hydrogen in the liquids (water or oil) occupying the pore space of core samples. Last month, a neutron radiography facility, the only one currently in Australia, was established in Perth.

To date, excellent (*and aesthetic*) quantitative images have been obtained for a suite of samples of Mardie Greensand from the Barrow Sub-basin. From these images, one can deduce total porosity, effective porosity, permeability and pore throat radius. One can also analyse dynamic core-flooding experiments to obtain relative fluid saturation and relative permeability. We have found that total porosity from the neutron analysis is very close to conventional Helium porosity, but considerably more information is obtained from the neutron analysis about pore and fluid distribution in the samples. Figures 1a and 1b illustrate an example from our suite of Mardie Greensand images, where the height of the pixels has been processed to represent water saturation.

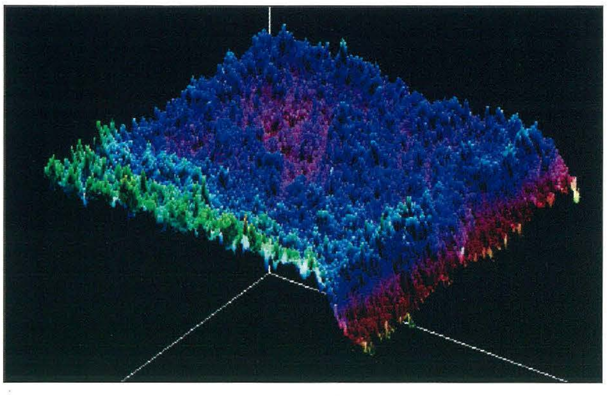

Fig. 1a. Perspective view of a neutron image of a partially saturated (1 hour spontaneous imbibition) sample of Mardie Greensand (Blue = high saturation and Maroon = low saturation). Measured (Helium) porosity = 28% and measured permeability = 63 mD.

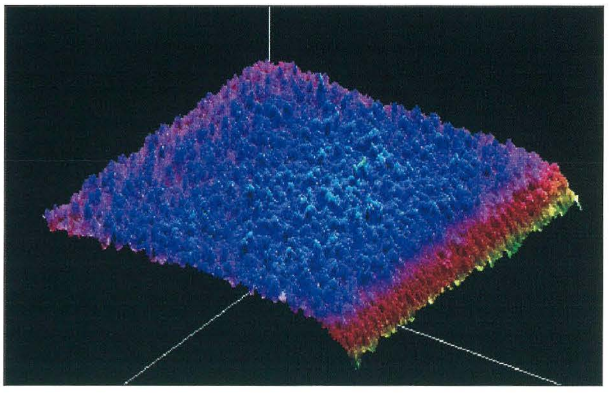

Fig. 1b. The same sample fully saturated (Blue = high saturation and Maroon = low saturation). Note that the central region with low saturation in Figure 1a now has the same saturation as the rest of the rock. The comparison of these two images suggests that the central region has the same porosity as the rest of the rock, but better permeability.

In principle, the analysis technique entails imaging a core in three states: (1) dry, (2) after spontaneous imbibition of liquid (usually water) into the core for a known period of time (usually one hour), and (3) fully saturated. Spontaneous imbibition is the process where the liquid enters the rock pores by capillary pressure only. Under spontaneous imbibition conditions, the liquid will preferentially enter the smaller pores, leaving the larger voids with gas (air in our experiments). By combining the physics of neutron attenuation with spontaneous imbibition, it can be shown that the heights of the pixels in the image shown in Figure 1a are proportional to the ratio of porosity to permeability (ϕ/k). Thus, we have a method to determine the porosity to permeability ratio at a very fine scale throughout a sample. In addition to this ratio, as previously mentioned, we can also estimate total porosity, fluid saturation and the distribution of mean pore-throat radii throughout the sample. The example in Figure 1 shows very nicely how various pore-throat distributions influence permeability, and the ability to recover oil (or water) from this rock type.