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Digital rock physics bridges scales of measurement

New sampling techniques bring field-size tests into the laboratory.

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It is human nature to evaluate a whole by breaking it into pieces. Relations can be obtained between remotely measured properties of sediment (such as the elastic-wave velocity) and its bulk, and transport properties (such as porosity and permeability) on small pieces of rock in the laboratory or in the well. Yet these relations are applied to discover, quantify, and forecast the behavior of a mass that is several orders of magnitude larger than the tests.

Will relations established at one spatial scale be valid at another? Not necessarily, mainly due to the heterogeneity of natural rock that persists at all levels.

To illustrate this, consider a 3-D micro image of oil sand (Figure 1). Even at this scale, a large variety of pore sizes and shapes can be observed. If porosity and permeability are measured in one corner of this cube with a massive fracture, those measurements would be quite different from that measured in another corner. Still, there is no alternative to using the results of controlled experiments in remote-sensing interpretation. The question is not whether to use such relations at the field scale but when and how to use them.

A way forward is to stage massive controlled experiments where different properties of rock are measured and interrelated at a varying spatial scale. This is hardly possible in the physical laboratory or in the well, where the scale of measurement is fixed. Moreover, as the depths, geometric complexity, and costs of new wells increase, core material and reliable well data become less and less available. Perhaps the only viable option is the emerging computational rock physics methods that allow experimentation with any rock fragments, including drill cuttings.

Computational rock physics

The approach of computational rock physics is to image and compute, i.e., image the details of rock structure at the pore scale and then accurately simulate a physical experiment in the computer. This idea is in no way new, but only recently have powerful 3-D scanners and computer clusters rendered this concept achievable in real time on such complex physical objects as natural sediment.

The procedure includes three major steps:

1. 3-D imaging of a rock fragment;
2. Image processing (segmentation) to discriminate pores from solid matrix and identify minerals within this matrix;
3. Accurate simulation of physical processes under precise experimental conditions.

The sample material for imaging can

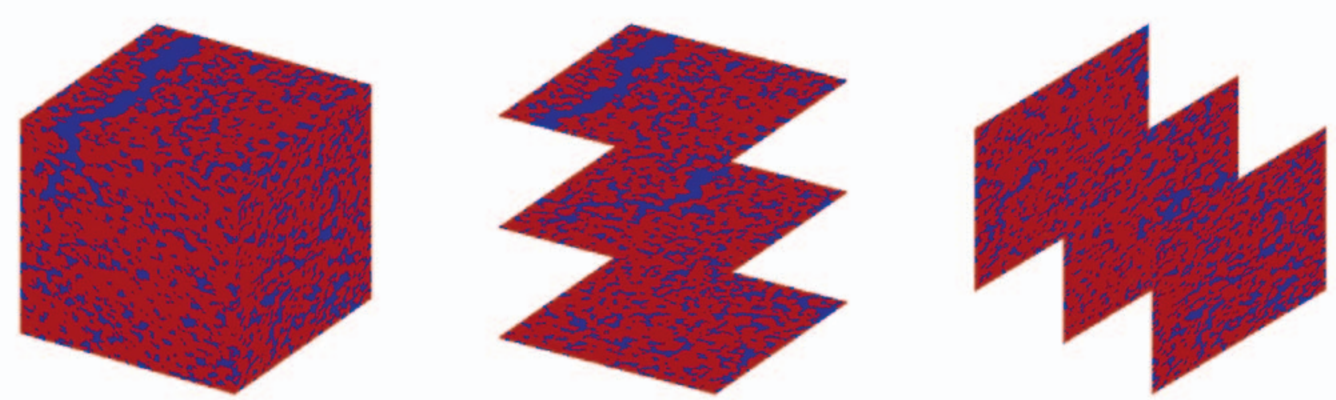

Figure 1. This image demonstrates a CT scan image of oil sand with a massive fracture in the upper left corner. The second and third frames display, respectively, horizontal and vertical slices of the rock. The size of this sample is about 3 mm. (Images courtesy of Ingrain Inc.)

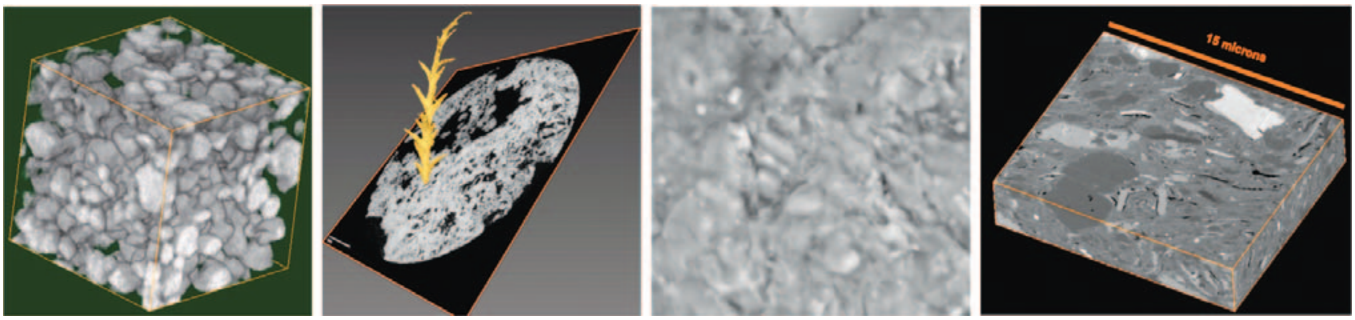

Figure 2. 3-D CT scan images of (from left to right) micritic carbonate, carbonate with vugs and a fossil, and black shale. The fourth image is an FIB-SEM 3-D image of black shale. This image has the same field of view as the third (CT-scan) image but permits a much higher resolution and clearly shows fine details that are blurred in the CT-scan image. The size of these images is 10 to 20 microns.

come from core, side-wall plugs, or drill cuttings. To cover the variability of scale-related properties, the first two sources are favored. One imaging technique employed at Ingrain is CT-scan tomography conducted at different scales and resolutions.

The digital experiment process begins with a team of trained geologists evaluating rock samples and preparing them for imaging with industrial-grade CT scanners. These scanners produce a 3-D reconstruction of an image that is delivered as hundreds of 2-D tomographic slices. Most conventional samples are imaged using a Micro CT system that functions at resolutions down to one micron. For shales and microporous carbonates, the company uses a Nano CT, the only machine of its kind currently being used in the oil and gas industry, which delivers resolution to 0.05 microns. The CT-scan images are delivered as gray-scale digital files.

CT-scan images are then subject to proprietary segmentation routines that differentiate pores from minerals and, within the mineral matrix, identify different mineralogy such as pyrite, calcite, or clay. The final result is a digital representation (which Ingrain calls a vRock digital reservoir rock) of the original physical rock with a finite number of components (just two components in the simplest case of segmentation into pores and matrix, as shown in Figure 1). vRock digital reservoir rock preserves the pore space in its complete intricacy and makes it ready for digital experiments. Such imaging and segmentation are usually sufficient for conventional reservoir rock.

Imaging shales

Even the Nano CT machine cannot resolve the very small and very important features of shales, which are rapidly becoming the unconventional sources of hydrocarbons. This is where a new imaging technique called FIB-SEM (focused ion beam combined with scanning electron microscope) comes in.

The focused ion beam tool is a device used, often in conjunction with a scanning electron microscope, to carry out micro- and nano-scale characterization of materials. Historically central in the semiconductor and material science industries, the FIB–SEM tool allows users to physically slice materials and to view them at very high magnification. The FIB system directs a high-energy focused beam (gallium in this case) at the mounted sample and cuts away material in a precise manner. The removed layer can be as thin as 2.5 nanometers. After a slice is removed, the SEM is used to acquire a high-resolution image of the newly exposed material. These consecutive slices comprise a 3-D image (Figure 2).

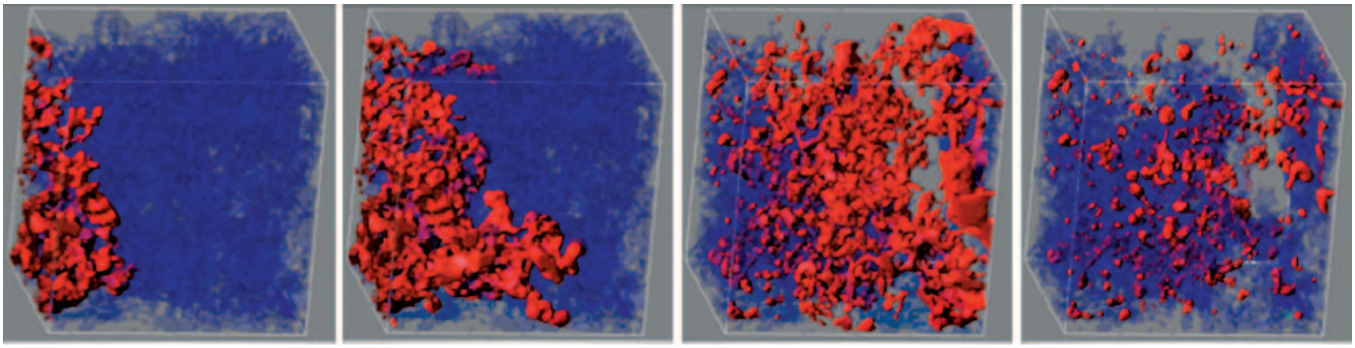

Figure 3. Two-phase fluid flow is simulated in a micritic carbonate sample at the pore scale. The first two images illustrate oil (red) moving into water-saturated rock. The last two images are water displacing this oil.

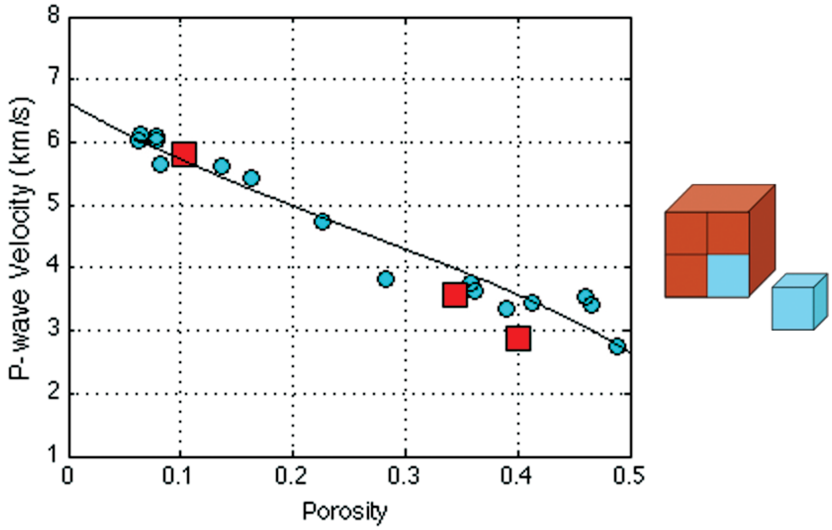

Figure 4. Shown here is the P-wave velocity versus porosity in micritic carbonate measured in the laboratory (red squares) and computed by subsampling small digital images (cyan circles). The cartoon on the right illustrates the subsampling procedure.

The final step includes computational experiments where fluid flow, electrical current, and elastic deformation are simulated in a segmented sample at desired conditions and selected transport agents. The results describe permeability, electrical conductivity, and elastic modules of rock. They are then compared to one another and also to the mineralogy and porosity of the sample to understand and quantify relations among these different attributes of rock.

Especially challenging, yet at the same time rewarding, are multiphase flow simulations, which provide relative permeability and capillary pressure. Ingrain's proprietary algorithms accomplish this task in real time, practically as fast as the samples arrive. These algorithms handle fluid phases of drastically different viscosity and surface tension. An example of such a simulation is shown in Figure 3, where the original water-saturated carbonate sample is flooded by oil and then water.

The numerical laboratory

One way of attacking the problem of translating results of controlled experiments into the field scale is to conduct these experiments on massive sets of representative rock samples and on samples of varying sizes. The latter is practically impossible in the physical laboratory but very easy in the numerical laboratory.

One approach is to subdivide an imaged and segmented rock into several subsamples (i.e., 2 x 2 x 2 = 8) and conduct digital experiments on each of these subsamples. This provides eight corresponding permeability, electrical conductivity, and elastic-wave velocity values. If these sets of data form a trend and the trend is supported by laboratory and theoretical rock physics, it can be assumed that it will persist at a larger field scale not covered in the experiments.

A striking example of this approach is shown in Figure 4. The experiment was based on three micritic carbonate samples. Porosity and velocity were first measured in the laboratory in each one. Next, small fragments of each sample were CT-imaged and their elastic wave velocity computed. These results are shown as red squares in Figure 4. Following this, the segmented images of each of the three original samples were subsampled, and porosity and velocity were computed for each subsample. These results are shown in Figure 4 as blue circles.

This subsampling process helps cover the porosity-range gaps between the original samples and even slightly extend the porosity range outside that present in the three selected samples. Moreover, the velocity-porosity trend evident in these subsamples matches and enriches that established in the original three samples. This trend is supported by a theoretical model relevant to this lithology. It is likely that such trends are applicable at a larger field scale.

Addressing the question of scale is especially challenging in hydrocarbon-producing shales. Shale samples are notoriously difficult to handle in the laboratory. Hence, computational rock physics becomes the leading means of quantifying shale reservoirs from remote sensing. For this reason, Ingrain has formed a Haynesville shale industrial consortium.

Shale samples and cuttings will be imaged at different scales, including macro-, micro-, and nano-CT machines. These images will be used not only to compute the properties of the samples but also to select smaller subsamples representative of different domains of shale. FIB-SEM will be used to image these fragments at the finest scale and then conduct computational experiments. The images and their physical properties will be spatially correlated at all of these scales to obtain a broad database and relations for predicting shale properties and performance in the field. This "panoscopic" approach will ensure the robustness of this pioneering field-oriented project on rock physics of shales.

As the demand for massive and accurate data in the industry rises, such "fearless" computing already significantly complements laboratory experiments and is likely to dominate in the near future. E&P