

The future of rock physics: computational methods vs. lab testing

Jack Dvorkin,^{1,2*} Meghan Armbruster,¹ Chuck Baldwin¹, Qian Fang,¹ Naum Derzhi,¹ Carmen Gomez,^{1,2} Boaz Nur,¹ Amos Nur^{1,2} and Yaoming Mu¹ propose the novel use of a virtual rock physics laboratory as a pragmatic way to improve the quantifying and understanding rock without damaging the usefulness of rock samples for further experimentation.

Physical measurements of rock properties on cores, plugs, and cuttings are cumbersome and often impossible to obtain or to obtain accurately. Any geophysical interpretation requires a transform from remotely measured quantities, like seismic impedance or EM-derived resistivity, to reservoir properties, such as porosity, hydrocarbon saturation, or permeability. A transform can be an experimental regression, or it may be a theoretical model, which still must be calibrated and verified by experiment. In either case, a substantial experimental data set is a cornerstone of interpretation.

To achieve the most accurate data sets, physical experiments demand intact rock samples extracted from a well. What will be needed in the future – for higher resolution seismic interpretation, reservoir characterization, reservoir simulations, and production management – are properties not for tens of samples but thousands or tens of thousands of samples. The traditional coring procedure is often problematic, because it leads to delays in drilling and carries the danger of damaging or even losing a well. Friable rock samples often simply cannot be delivered intact from the subsurface to the laboratory. Oil sands are an important subset of this group, in which bitumen acts as the load-bearing framework. Cleaning and transportation of such rock, as may be necessary for fluid flow experiments, destroys its texture.

For these reasons, the petroleum industry more and more often exploits the well as a laboratory. Modern logging tools employed during and after drilling provide reliable quantification of the elastic properties of rock, its porosity, mineralogy, and the pore fluid within an extensive depth range. By inter-relating these groups of parameters, we can establish empirical regressions or select appropriate theories as transforms from elastic to bulk properties (Figure 1).

Well data may be suitable for relating the elastic properties to porosity, mineralogy, and fluid. However, the absolute and relative permeability simply cannot be measured robustly in the well. This is why permeability, highly coveted by engineers, has been accessible only in the laboratory.

Primer on permeability

The definition of *absolute permeability* is based on Darcy's equation, which linearly relates the volume flux to the pressure difference between the two faces of a sample:

$$Q = -k \frac{A \Delta P}{\mu L},$$

where Q is the volume flux, A is the cross-sectional area of the sample normal to the direction of the flow, ΔP is the pressure difference, μ is the dynamic viscosity of the fluid, L is the length of the sample in the flow direction, and k is permeability, measured in Darcy. Its physical unit is length squared, with one Darcy equaling 10^{-12} m².

A simple but often incorrect way of estimating k is from the Kozeny-Carman equation:

$$k = \frac{1}{2} \frac{\phi^3}{S^2 \tau^2} = \frac{d^2}{72} \frac{\phi^3}{(1-\phi)^2 \tau^2},$$

where ϕ is the porosity open to the flow; S is the specific surface area, defined as the ratio of the area of the pore walls to the total volume of the sample; $\tau \geq 1$ is the tortuosity, defined as the ratio of the length of the flow path to the length of the sample; and d is the average grain size.

This equation implies that k depends not only on porosity but also on the grain (or pore) size. This is why some high-porosity shales have very low permeability. An experimental illustration of this effect (Figure 2) comes from Yin (1992). In this example we observe a dramatic reduction of k during the transition of the specimens from sand to clay, even though ϕ increases during this transition.

There is one more rock property that often makes analytical estimates of permeability questionable: the connectivity of the pore space. Consider the carbonate thin section in Figure 3. Its porosity is large, and the fluid is contained in relatively large vugs. However, most of these vugs are disconnected from each other. As a result, the flow

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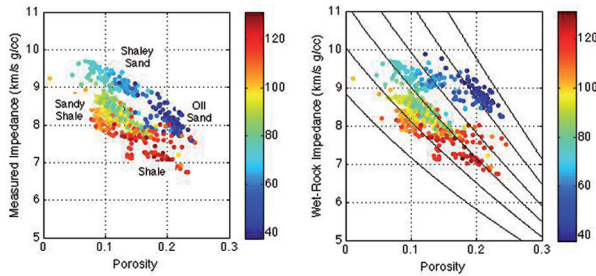


Figure 1 P-wave impedance versus the total porosity in an oil well. The data are colour-coded by the gamma-ray measurement (GR). Left: Measured impedance. The blue datapoints represent oil sand. Right: Impedance theoretically calculated for wet-rock conditions from the measured impedance. The position of the sand (now wet) moved upwards. The black curves come from a theoretical stiff-sand model (Gal et al., 1998). These model curves are calculated for the quartz/shale mineralogy with zero clay for the top curve and zero quartz for the bottom curve. The clay content increment between two successive curves is 0.2. This model can now be used to interpret impedance data away from well control.

conduits are restricted, if they exist at all. The permeability of such rock may be extremely small.

If a sample is filled with two fluids, the relative permeabilities, k_{r1} and k_{r2} , are defined as

$$k_{r1} = -\frac{Q_1 \mu_1}{kA \Delta P / dx}; \quad k_{r2} = -\frac{Q_2 \mu_2}{kA \Delta P / dx},$$

where the subscripts ‘1’ and ‘2’ refer to the first and second fluid, respectively. Relative permeability, unlike the absolute permeability, is unitless.

An empirical Corey-type equation for relative permeability is

$$k_{r1} = S_{rr}^n; \quad k_{r2} = (1 - S_{rr})^m,$$

where $S_{rr} = (S_1 - S_{1irr}) / (1 - S_{1irr} - S_{2irr})$; S_1 is the saturation of the pore space by the first fluid; S_{1irr} is the irreducible saturation of the first fluid; and S_{2irr} is that for the second fluid. The n and m values are generally assumed based on experiments, but $n = m = 2$ may suffice. An example of relative permeability curves according to this equation is shown in Figure 4 for $n = m = 2$ and $S_{1irr} = S_{2irr} = 0.1$.

Even if this equation is sometimes correct, its parameters must come from laboratory experiments, which are notoriously difficult to stage and take a long time to complete.

Virtual experiments

It is possible to simulate some natural processes by either theoretical modelling or digital virtual experimentation. Virtual experimentation requires an accurate 3D image of rock with clearly identifiable pore-scale features, plus powerful codes that accurately simulate a physical process.

The idea of virtual experimentation is not new. However, only now can powerful 3D scanners and computer clusters render this concept realizable on such complex physical

objects as natural rocks. It is not yet possible to theoretically mimic the full complexity of nature, but there has been some success in simulating single or multiphase flow, electrical current, and elastic deformation.

Imaging

Modern CT scanners can produce 3D images of rock with the high accuracy and resolution required for staging virtual experiments at the finest scale. Such an image is shown in Figure 5. It consists of a large number of 2D tomographic slices that are collected together to create a 3D representation of real rock.

Examples of these tomographic slices taken from different rock types are displayed in Figure 5. We can see the finest pores and cracks in the tight gas sandstone; pores filled with bitumen and air as well as fine pore-filling particles in the oil sand; and fossils in the carbonate.

The complexity of the pore space revealed in these images is daunting. Such geometries may not be amenable to any idealized representation, including conduit networks made of storage nodes and connectors between them. Moreover, these images render irrelevant several simple concepts employed in the industry, including idealized pore shapes, pore throats, grain size, and tortuosity. To fully exploit the richness of information contained in such images, we must embrace their intricacy and accurately simulate physical processes within this complex framework.

Quantitative virtual laboratory

A digital tool suitable to this task is the lattice-Boltzmann method (LBM). It accurately simulates the Navier-Stokes equations of slow viscous flow and, most importantly, easily accommodates the complexity of the pore-space boundaries (e.g., Rothman and Zaleski, 1997). Once the flow process is

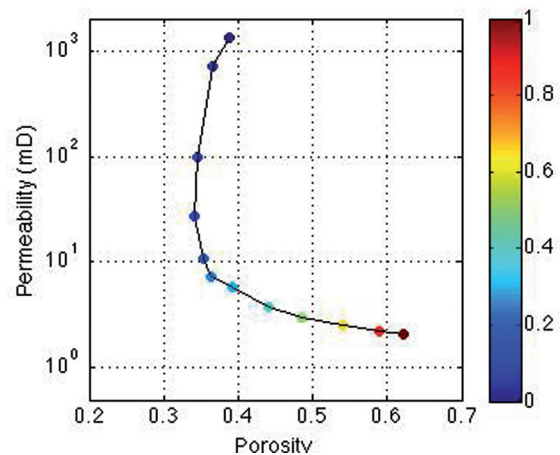


Figure 2 Permeability versus porosity as measured on a set of Ottawa sand and kaolinite mixtures (Yin, 1992). The clay content varies from zero to one. The symbols are color-coded by the clay content.

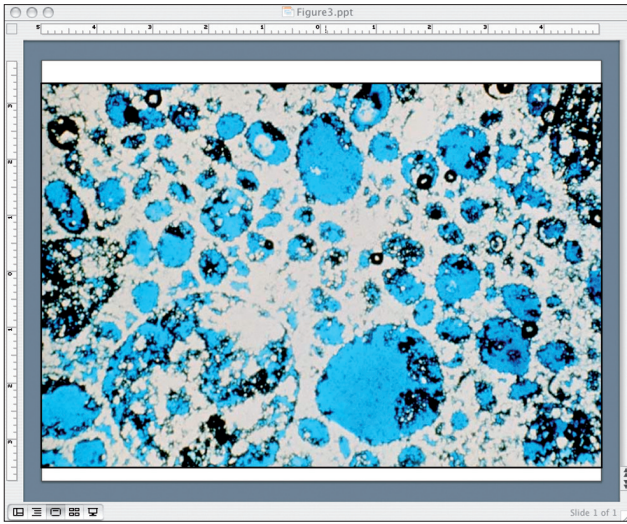


Figure 3 A thin section of a vuggy carbonate. Blue is the pore space.

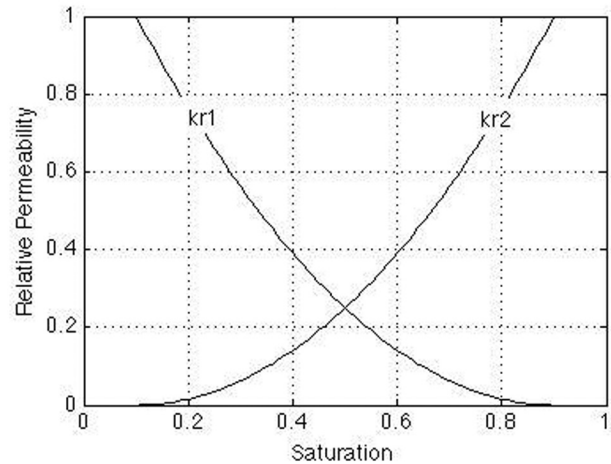


Figure 4 Relative permeability versus saturation for the above-described example.

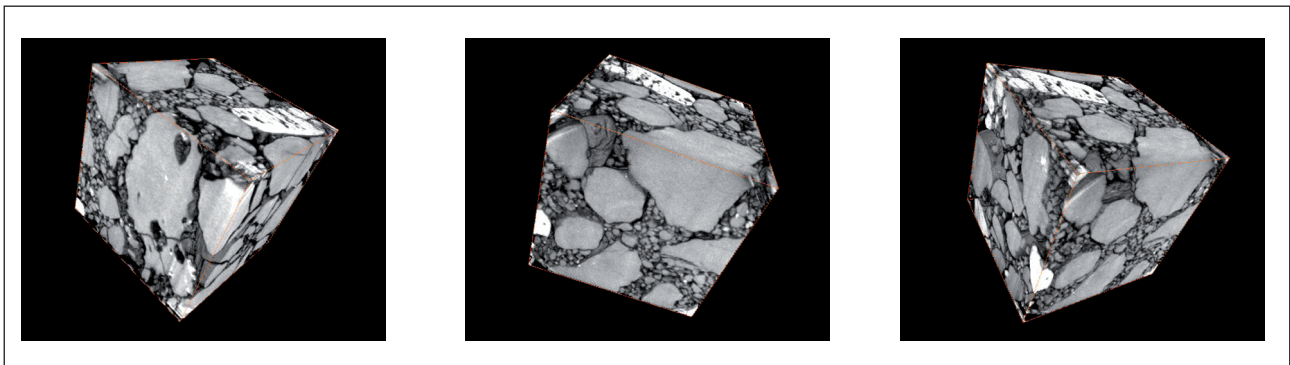


Figure 5 3D views of an oil sand sample with large grains and small particles filling the pore space. The cube displayed is about 1 mm in size.

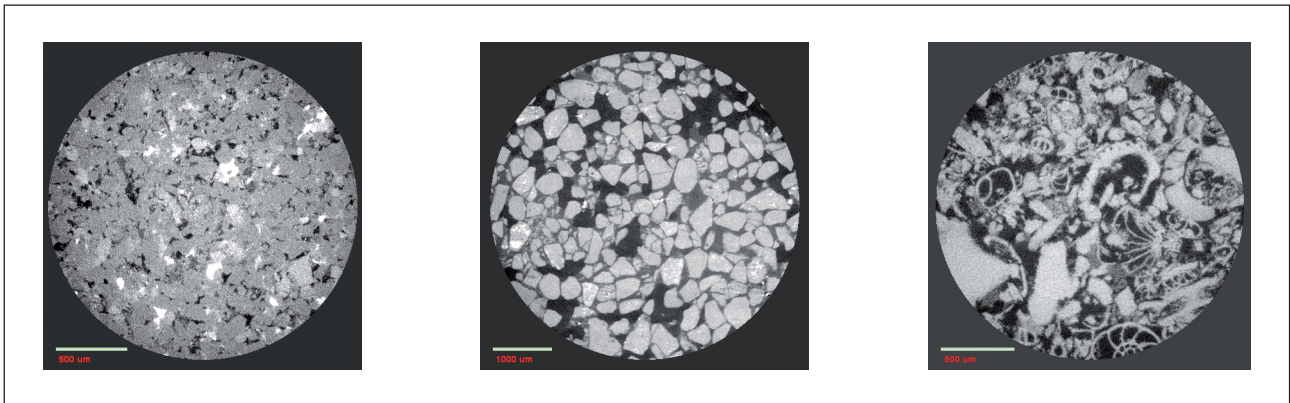


Figure 6 Tomographic slices of 3D images of tight gas sandstone (left), oil sand (middle), and carbonate (right). The scale bar from left to right is 0.5, 1.0, and 0.5 mm.

simulated, the absolute permeability is derived from Darcy's equation, the same way it is done in the physical laboratory. Such virtual results for carbonate samples are compared to laboratory data in Figure 7.

The virtual permeability generally follows the physical permeability, but in some instances it is quite different. This

may be disappointing unless we contemplate the reasons. In fact, the virtual and laboratory permeabilities *do not have to be the same*, especially in carbonate: physical experiments are conducted on samples a few centimeters in size while virtual experiments deal with a millimeter scale. Real rock is heterogeneous at all scales, so this mismatch is not surprising.

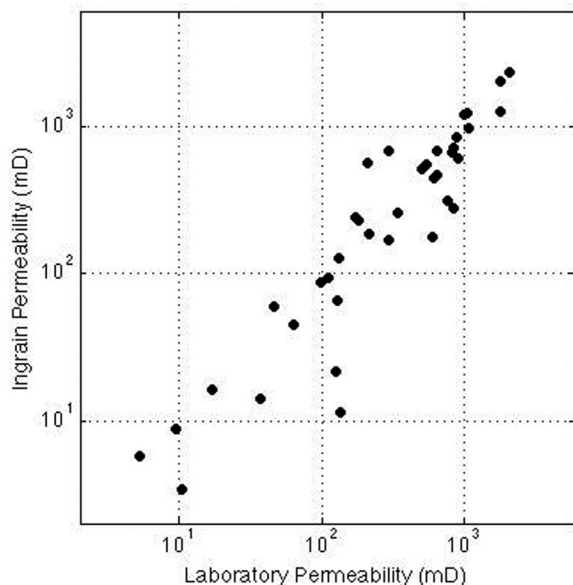


Figure 7 Absolute permeability computed from 3D images of carbonate samples using LBM versus that measured in the laboratory.

Quantitative virtuality naturally provides a cure for this mismatch. It helps *embrace heterogeneity* because digital experiments can be efficiently conducted on a large number of small samples situated as close or as far apart in the real rock as desired. This is simply impossible in the physical laboratory. An example of this paradigm is illustrated in Figure 8, where porosity and permeability are calculated on CT images of a set of very small (about 1 mm) Berea sandstone chips. At the same time, these parameters are calculated on a larger sample's image (about 3 mm). As expected, the permeability-porosity pairs vary through this set of data due to the spatial heterogeneity of the physical sample. However, the data form a trend that is practically usable and also provides a measure of the natural uncertainty of porosity and permeability.

The quantitative virtuality approach allows experiments on physical materials and microsamples that cannot be handled otherwise. It literally lets us look deeper into the nature of rock and discover new laws and relations.

Multiphase flow

Relative permeability is notoriously difficult to measure physically, because when more than one fluid flows through a sample, it is difficult and time-consuming to insure stable saturation. In friable samples, such as oil sands, such experiments may be impossible, because the sample's texture will be destroyed when the bitumen is removed. Virtual experiments provide a unique possibility of simulating multiphase flow in any sample, with any irregular shape, and with fluids of any specified viscosity and wettability. Figure 9 is a snapshot of a transient process of oil invading a pack of glass

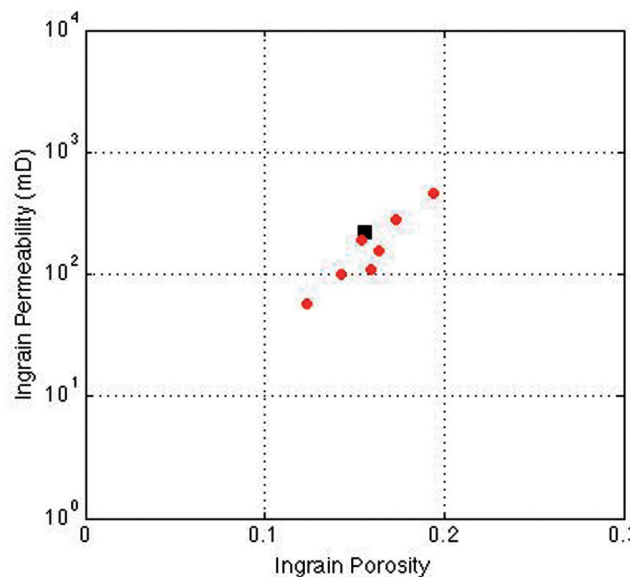


Figure 8 Absolute permeability computed from 3D images of small Berea sandstone chips (red). The black square is calculated from a larger chip.

beads initially saturated with water.

Figure 10 displays a series of such snapshots for oil replacing water in water-wet carbonate. The digitally obtained relative permeability curves for this sample are plotted in Figure 11.

Formation factor and resistivity

The same virtual object, a 3D image of rock, can be used to digitally obtain the electrical properties of rock. The electrical current responding to an imposed potential field is calculated using a powerful finite element (FEM) computational engine. If rock is fully saturated with conductive fluid (e.g., brine), this experiment provides us with the formation factor F , which is, by definition, the ratio of the wet sample's resistivity, R_{wet} , to that of the brine, R_w : $F=R_{wet}/R_w$. A commonly used equation is $F=a/\phi^m$, where a is a constant coefficient and m is the cementation factor. If rock is partially saturated with hydrocarbon, which is usually a dielectric, the water

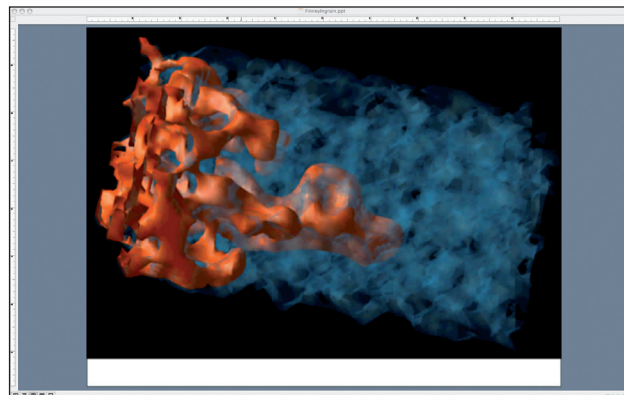


Figure 9 Oil (brown) replacing water in a glass bead pack.

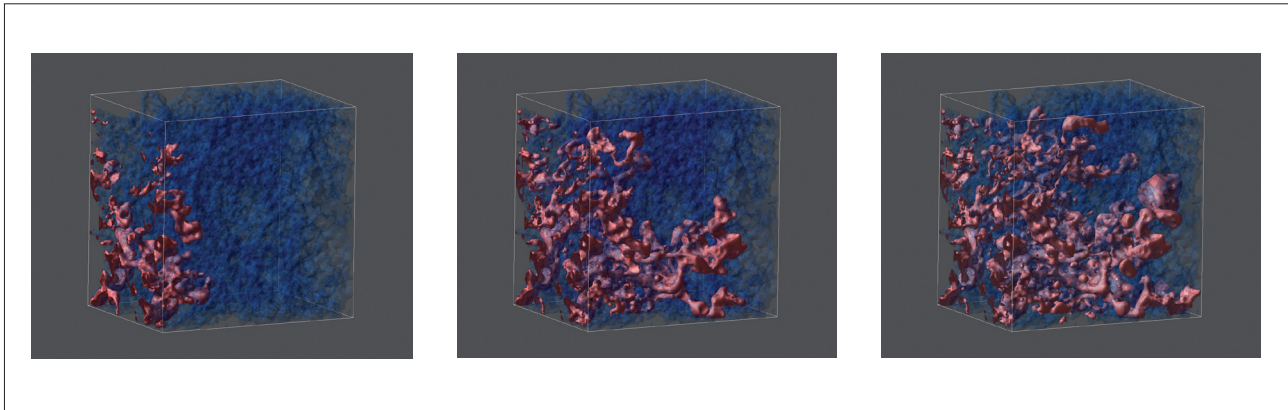


Figure 10 Oil (brown) replacing water in oil sand.

saturation S_w is often calculated as $S_w = (FR_w/R_p)^{1/n}$, where n is the saturation exponent. These constants, a , m , and n , are needed to estimate hydrocarbon volume at a well from resistivity measurements. Virtual electrical flow experiments conducted on a number of samples (e.g., drill cuttings) from an interval of interest allow us to obtain these constants in real time and establish how they vary with varying formation type and pore-fluid distribution. Realizations of the pore-fluid distribution can come from the multi-phase flow experiments conducted on the same (shared) digital rock.

Elastic and inelastic properties

Once again, the same virtual object can be digitally deformed with prescribed strain to calculate the resulting stress using the FEM. By relating stress to strain, we obtain the elastic moduli of the rock and find how they vary with porosity, mineralogy, and rock texture. Of course, the elastic moduli can be measured in a well if the P- and S-wave velocities and bulk density are available. The advantage of virtual experimentation is that it is conducted on a shared digital object and simultaneously provides all desired properties of this object, including permeability. This provides us with a unique opportunity to establish and understand relations among these properties.

Seismic-wave attenuation is another important quantity that field geophysicists want to obtain. It can result from fluid movement in the pore space and from elastic heterogeneity of the rock frame. Both factors can be explored digitally, thus providing quantitative estimates of attenuation in reservoir and non-reservoir formations.

Challenges

As with any experimental setup, the virtual laboratory poses a number of technical challenges. One such challenge is accurate quantification of a 3D CT scan in terms of the pore space and minerals present (Figure 12). The former is the starting point in any virtual rock modelling, but it is the latter that controls the elastic and electrical properties,

especially if conductive minerals (e.g., pyrite and porous clay) are present. The task is to segment a 3D gray-scale image into a finite number of domains and assign properties to these domains. Sometimes it is formally impossible, because of the presence of sub-resolution particles in clay or micrite. This is where additional information, such as from scanning electronic microscopy (SEM) and x-ray diffraction (XRD), as well as petrological knowledge is required. Often, computational mathematics applied to real rock will not provide a correct answer, unless verified by deep expertise and common sense.

As with any new experimental tool, the virtual laboratory not only provides answers, but also creates new questions. One fundamental question is related to scale: what do massive data obtained on very small fragments tell us about rock properties at a reservoir scale? As with any question, this one first must be properly posed. Once it is, the answer(s) will certainly lead us towards better characterization of the subsurface and, eventually, better recovery of hydrocarbons.

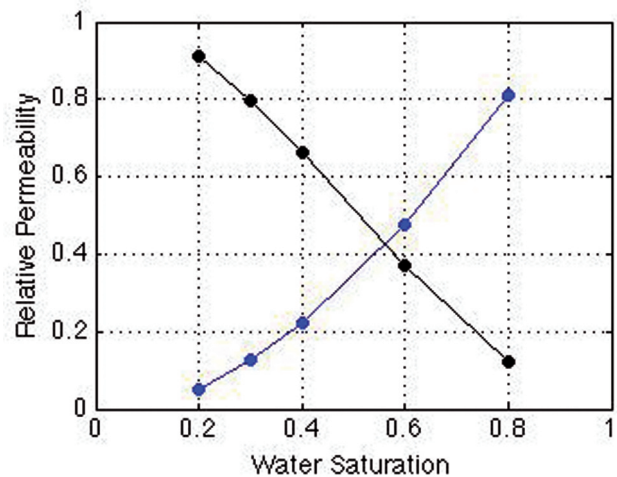


Figure 11 Digitally obtained relative permeability versus water saturation for water (blue) and oil (black) in a carbonate sample.

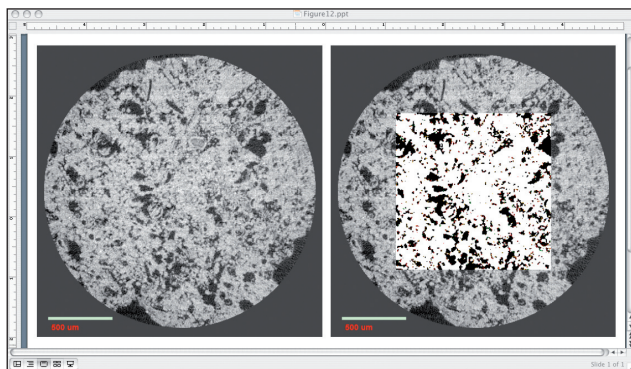


Figure 12 A tomographic slice of a 3D image of a carbonate sample. Left: the original image. Right: image segmented into the pore space (black) and matrix (white). The scale bar is 0.5 mm.

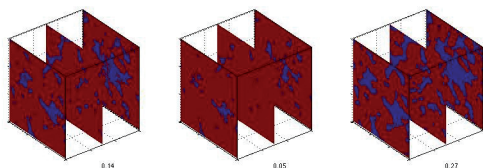


Figure 13 Original sample of sandstone (left) with pore space eroded to simulate cementation (middle) and the mineral matrix eroded to simulate early sedimentation (right). Porosity is shown as numbers below the images.

Conclusion

The paradigm of the virtual rock physics laboratory, executed using state-of-the-art imaging and computing techniques, opens a new avenue to quantifying and understanding rock. It generates massive data in real time on fragments that cannot be handled otherwise. It allows us to simulate changes, such as diagenesis, or, in other words, move rock through geologic time and space by applying relevant mathematical transforms to a digital image of a sample taken today and at a known location (Figure 13), all without destroying the sample's usefulness for further experimentation. The full span of applications of this paradigm is still evolving, but one thing is clear: it will contribute to both applied technology and fundamental science.

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