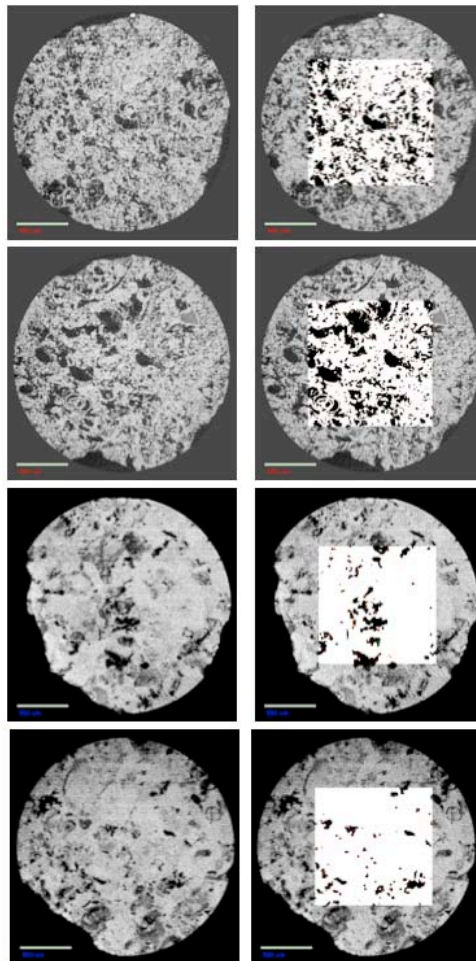


Measuring Carbonates

Carbonate reservoirs contain vast volumes of natural oil and gas throughout the world, particularly in the Middle East. The physical properties of carbonates, especially permeability, are often dominated by a complex pore structure created from fossilized micro-shells and skeletons. Geologically rapid diagenetic transformations also contribute to this complexity.

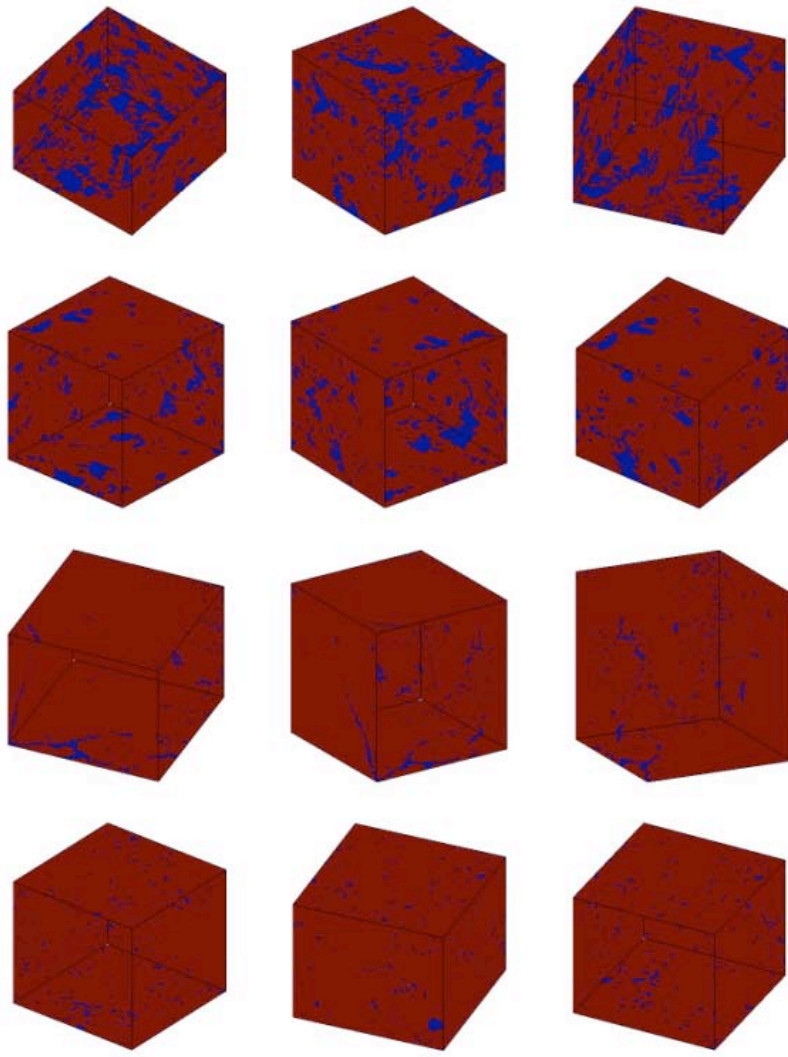


Four carbonate samples imaged in micro-CT. Displayed are 2D radial slices of 3D images. Left column: gray-scale images with minerals light and pores dark. Right column: the same slices but image-processed to separate the mineral matrix (white) from pore space (black). Two top rows show medium-porosity carbonate with discernible fossilized skeletons. The lower two rows show smaller-porosity samples with some of the pores disconnected from the pore-space network. The scale bar is 0.5 mm.

Because of this complexity, physical experiments on carbonates, unlike clastics, often

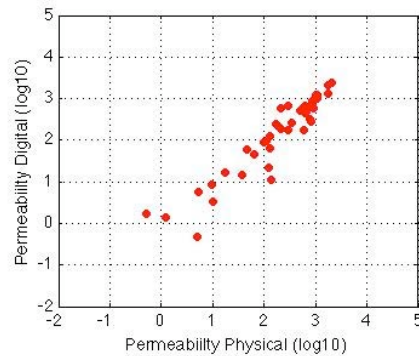


resist generalization. Carbonates are excellent candidates for the digital rock technology where the intricate features of the pore space are first imaged at a required magnification to obtain 3D digital objects that reflect the actual physical specimen, be it part of a core, sidewall plug, or drill cutting.



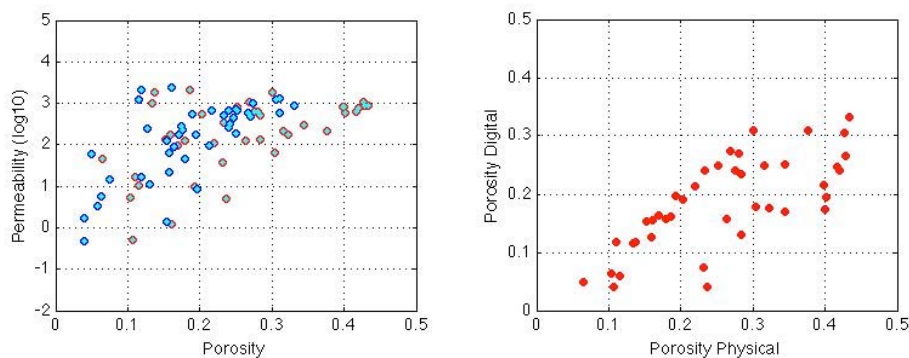
3D renditions of four carbonate samples imaged in micro-CT with the images segmented to discriminate pores from the mineral matrix. Pores are blue, while the matrix is red. Each row shows a separate sample in different perspectives. The size of the side of these cubes is between 0.7 and 1.5 mm.

Computational fluid flow experiments on carbonate 3D images provide fairly reliable absolute permeability values, which closely match physical laboratory data.



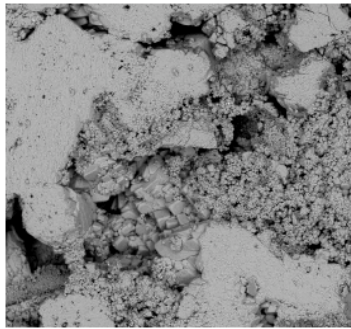
Permeability (decimal logarithm, mD) as calculated from 3D images of carbonate samples versus that measured in the laboratory. The samples and laboratory data courtesy Cinzia Scotellaro (Stanford University).

It is interesting, however, that if we plot permeability versus porosity for the same dataset, a mismatch between the physical and digital porosity for some of the samples is apparent, while the digital and physical permeability values match.



Left: Permeability (decimal logarithm, mD) versus porosity as calculated from 3D images of carbonate samples (blue rim) and the same measured in the laboratory (red rim). Right: porosity as calculated from 3D images of carbonate samples versus that measured in the laboratory. The samples and laboratory data courtesy Cinzia Scotellaro (Stanford University).

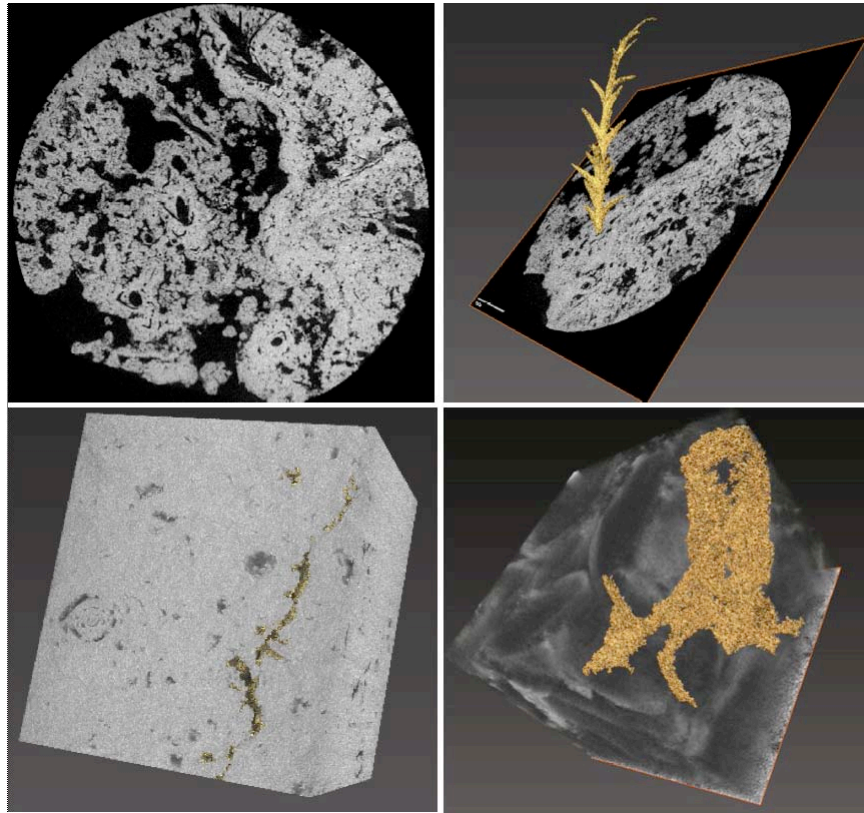
The reason for this porosity mismatch is the presence of micrite (microcrystalline calcite - usually less than 5 micron in size), which is found as a matrix in many limestone samples. Micro-CT images did not resolve the nano-porosity present within the micrite matrix.



An SEM image showing nano-size porous micrite next to solid calcite grains (courtesy Cinzia Scotellaro and Tiziana Vanorio (Stanford University)).

The digital permeability of carbonate, as obtained by Ingrain, appears to be correct (in spite of this porosity mismatch) simply because the micrite matrix, although porous, does not permit any flow, due to its extremely small permeability, which is, in turn, due to the very small grain size. This means that the micro-CT resolution used by Ingrain in this example is satisfactory for fluid flow simulations and permeability quantification.

The nano-CT scanners at Ingrain can resolve features as small as internal micrite pores as such features become salient for computing the physical properties of carbonate.



CT-scan images of carbonate samples with (clockwise from top-left) complex pore space that includes large pores as well as nano-pores inside solid matrix; a 3D image of micro-coral superimposed on a 2D slice; fracture-related pore space; and intergranular pore space delineated.

About Ingrain

Ingrain's digital rock physics lab computes the physical properties and fluid flow characteristics of oil and gas reservoir rocks. Our technology leads the industry in providing advanced rock properties analysis for shale, carbonates, tight gas sands and oil sands. Using core plugs or even drill cuttings, Ingrain can deliver accurate results as fast as 14 days.

A trained geologist uses micro- and nano- resolution CT scanners to digitize the fabric of each rock sample. Each set of scans is combined and segmented to create a vRock – a high resolution 3D image of the actual pore network and grain structure. Our supercomputing clusters use proprietary algorithms to computer rock properties and fluid flow characteristics from each vRock:

Physical Rock Properties

> Porosity



- > Absolute permeability in three axes*
- > Electrical properties in three axes*
- > Elastic properties, including compression and shear acoustic velocities, Bulk modulus, Young's modulus, Shear modulus, and Poisson's ratio*

Multiphase Flow

- > Two-phase relative permeability: water-oil, gas-oil, and water-gas displacement at different wettability indices and viscosity values in three axes*

*To learn more about Ingrain's services and the science we use, please visit www.ingrainrocks.com
www.ingrainrocks.com*