INGRAIN
Digital Rock Physics Lab

CASE STUDY

Properties of Tight Gas Sands

Challenge

Extremely low and often disconnected porosity makes measuring permeability of tight gas sands notoriously difficult and unreliable. Ingrain was asked by the operator of a gas field in the Williams Fork Formation of the Colorado Basin to directly determine permeability without resorting to the standard but intricate and indirect technique of pulse-decay flow measurement.

Solution

Utilize CT scanning at the nano-meter level of resolution as input to 3D flow computations, delivering a host of physical and flow properties of the reservoir.

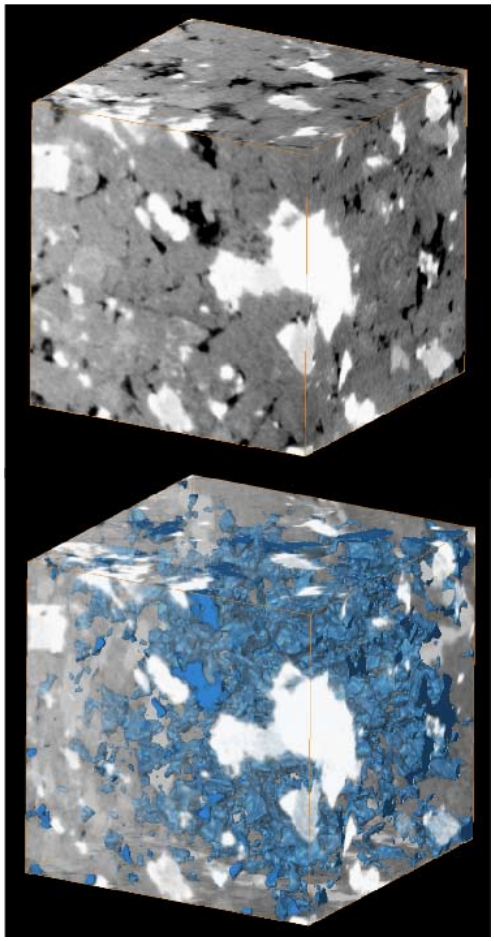
Results

Pore structure, pore size and pore distribution (larger pores associated to calcite) and their resulting permeability, computed in conjunction to elastic properties, allowed the operator to determine variations in sonic logs and how they correlate to reservoir quality. By recognizing the association of high calcite content with the enhancement of porosity and permeability, the operator can now identify and correlate the best flow units.

Imaging and computing with enough resolution

Two samples were imaged and computed:

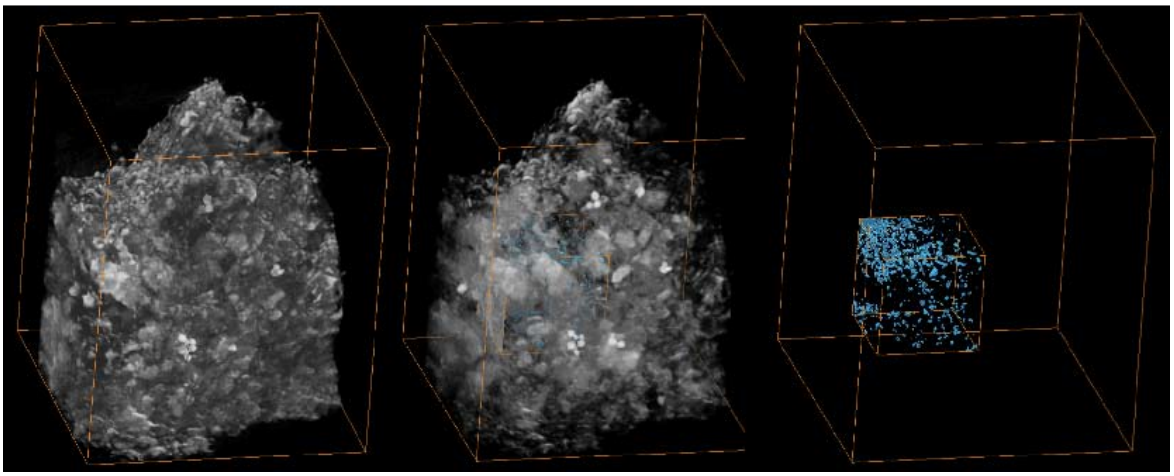
The porosity of the first sample was about 0.08. Fairly large pores connected by narrow conduits dominated it. This pore space was successfully imaged in a micro-CT (Computed Tomography) machine with a voxel resolution of 2.2 microns. The simulated permeability was in the 1 to 5 mD range. The formation factor ranged from 600 to 2,000.



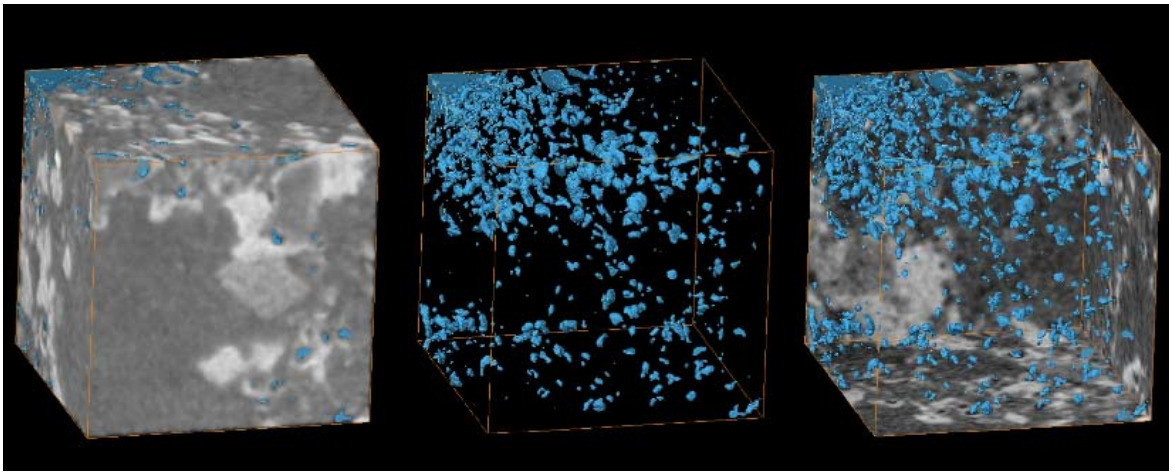
Pore space (blue) rendition of a 1mm cube of the first sample

Case Study: Properties of a Tight Gas Sand

The pore space of the second sample was not discernible at the micro-CT resolution. It was imaged in a nano-CT machine with a voxel resolution of 0.065 microns. Disconnected spherical pores of approximately 1 micron in size were discovered. These pores were predominantly located within calcite crystals, presumably due to secondary dissolution of carbonate inclusions.



A three-dimensional view of the sample scanned with the nano-CT system. The matrix is made transparent to show a sub-region selected for porosity calculations, shown in the small 20-micron cube in blue.



A three-dimensional view of the sub-region of a 20 micron cube. The image on the left shows the solid phase in gray and the pore space in blue. The central figure shows only the pore space, and the image on the left shows the exterior bounding Slices of the cube.

Calcite inclusions and permeability

Nano-scale imaging and computations showed that pores were predominantly disconnected and located within calcite crystals. Computed permeabilities, in conjunction with elastic properties, allowed the operator to determine variations in sonic logs and how they correlate to reservoir quality. By recognizing the association of high calcite content with the enhancement of porosity and permeability, the operator can now identify and correlate the most promising flow units.