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Revolutionizing Core Analysis

Houston-based Ingrain uses latest-generation 3D CT (computed tomography) to quickly and accurately determine absolute and relative permeability, resistivity, elastic properties, pore and grain statistics. Results are available in days, they claim, even in ultra-low permeability sandstones, complex carbonates and shales.

The physical experiments required for special core analysis (i.e. relative permeability and capillary pressure) are expensive, time-consuming and difficult to conduct. Borehole stability concerns can prevent wells from being cored, while new technologies such as coiled tubing drilling mean that whole cores or sidewall cores are not available for analysis. To address this growing technical challenge, Houston-based Ingrain has introduced a series of technical breakthroughs in 3D imaging and computation of reservoir rock properties. Physical measurements that require weeks or months in a physical lab can now be completed in a matter of days on any rock material, including sidewall core plugs and drill cuttings.

Latest Generation Imaging

Ingrain's process begins by having a geologist conduct a low-resolution CT scan to map the density and assess the heterogeneity of each rock sample (typically a core plug.) The Ingrain geologist uses this scan to decide whether to use a Micro CT scanner (resolution of 1 micron) or Nano CT scanner (resolution of 0.05 microns) to capture a high-resolution 3D image. The Micro CT scanner requires a 2.5mm diameter micro-core rock sample, which is taken from a carefully selected location in the core plug or whole core section. If the geologist determines that Nano CT scanning must be used, a 0.5mm diameter micro-core is taken. Drill cuttings typically do not require an initial low resolution scan, and are instead imaged in a special Micro CT scanner that was designed specifically for use with drill cuttings.

After imaging, the Ingrain geologist uses specialized image processing software to differentiate the pore space from the grains. Within the mineral matrix, Ingrain can identify different mineralogy (e.g., pyrite versus calcite versus clay). The final result is a vRock™ digital reservoir rock that captures the pore space geometry and grain structure at sufficient resolution and detail so that physical properties and fluid flow characteristics.

Micro CT scanning has sufficient resolution to compute rock properties for sandstones, oil sands, most carbonates and tight gas sandstones. However, some carbonates, tight gas and shale formations require imaging at much higher resolutions. In the case of gas shales, it is essential to image the pore spaces at resolutions as high as 5 nanometers. For these rock samples, Ingrain uses a newly developed FIB-SEM (focused ion beam scanning electron microscope).

High Performance Computing

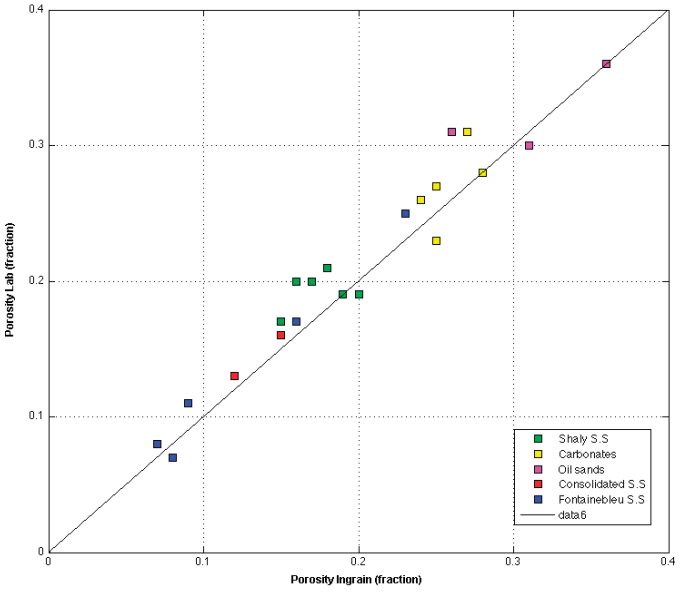
Ingrain first computes porosity as the ratio of the number of voxels that fall into the segmented pore space to the total number of voxels in a 3D image. Both effective porosity and isolated porosity are provided.

Absolute Permeability: Ingrain's absolute permeability computation simulates a laboratory measurement within the vRock™ digital reservoir rock using the lattice Boltzmann method (LBM). The resulting fluid flux is computed and permeability is calculated according to the Darcy's equation.

Formation Factor: Ingrain computes electrical conductivity (formation factor) in three directions by solving the Laplace equation in the conductive pore space by means of the finite element method (FEM). Ingrain's method directly accounts for conductive components of the mineral matrix, such as pyrite or conductive clay, by assigning appropriate specific conductivity to these components.

Elastic Properties: Elastic properties are computed by simulating a static deformation experiment on the vRock™ digital reservoir rock. Results include Bulk modulus (K), compressional velocity (Vp), Young's modulus (E), Shear modulus (G), Shear velocity (Vs), and Poisson's ratio.

Relative Permeability: Ingrain computes relative permeability on the vRock™ digital reservoir rock using the lattice Boltzmann method (LBM). Ingrain provides two-phase relative permeability (water-oil, gas-oil, and water-gas displacement at different wettability indices and viscosity values) in three axes, as well as irreducible water saturation and residual oil saturation.



Validation Results: Digital and Physical Measurements an Excellent Match

Advantages over Conventional Physical Lab Analysis

Digital rock physics has a significant advantage over physical measurements because it produces infinitely reusable digital reservoir rock samples. A digital rock physics database in provides the knowledge to maximize recovery rates in complex formation, where the inherent heterogeneities require large amounts of data to create accurate reservoir models.

Ingrain has made the digital rock physics lab a working reality.