INGRAIN
Digital Rock Physics Lab

INGRAIN, INC.   July, 2009

Examples of validation for Porosity, Permeability, Electrical and Elastic Properties.

Motivation

The science of digital rock physics is now maturing into a robust technical solution for measuring reservoir rock properties and fluid flow characteristics. For decades, the oil and gas industry has attempted to employ this paradigm that includes imaging (photography, SEM, CT scanning) and computation (image processing and physical process simulation) to better understand rock properties. It is only within the past few years that imaging technology and computing power has have advanced to the point where digital rock physics provides data that equals, or in many cases exceeds, the quality and quantity of results achieved by physical measurements.

The motivation for digital rock physics comes from the fact that physical measurements of reservoir rock properties are slow and cumbersome, and often impossible to do at all. Ingrain provides accurate rock properties analysis for sandstones, shales, carbonates, tight gas sands and oil sands. Results can be delivered as fast as 14 days (or even in real time as rock fragments become available) for any formation type. Because of the breakthrough nature of Ingrain's technology and the departure it represents from traditional physical core analysis, it is useful to compare the results from digital analyses to the results of physical experiments on comparable reservoir rock samples. This paper provides comparisons of data from Ingrain's digital rock physics lab to data obtained from physical lab measurements on identical or highly similar rock samples.

Porosity

Ingrain computes porosity directly from high-resolution segmented 3D images of reservoir rock samples. Image segmentation accurately separates the pore space from the mineral matrix. Porosity is directly calculated 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.

•Results provided: total, connected, and isolated porosity

Absolute Permeablity

Ingrain's absolute permeability computation simulates a laboratory measurement within the vRock (as we call a segmented CT-scan image). In this simulation, a pressure head or body force is directly applied to a digital sample. The slow viscous flow needed for such permeability estimates is simulated using the lattice Boltzmann method (LBM). The resulting fluid flux is computed and permeability is calculated according to Darcy's equation. Permeability is computed in three directions and delivered in milliDarcies (or nanoDarcies in very tight formations).

•Results provided: Permeability in X, Y and Z directions

Electrical Conductivity

Ingrain computes formation factor directly on a vRock digital reservoir rock sample by solving the Laplace equation in the conductive pore space, which was digitally completely saturated with brine, by means of the finite element method (FEM). The electrical current field in the pores is computed and then summed-up to obtain the total current through the sample. The effective conductivity of the sample is simply the ratio of this current to the potential drop per unit length, and the formation factor is the ratio of brine conductivity to the conductivity of the sample.

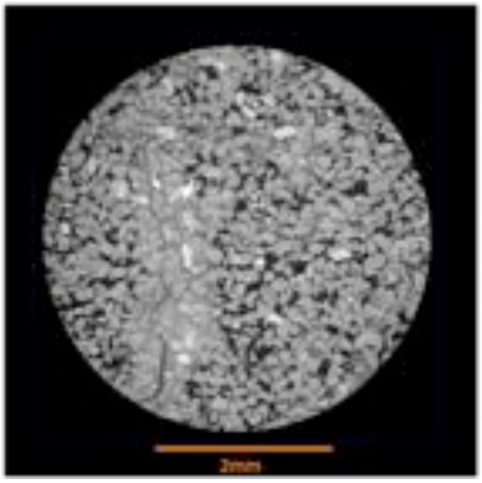
•Results provided: Formation factor in X, Y and Z directions

Elastic Properties

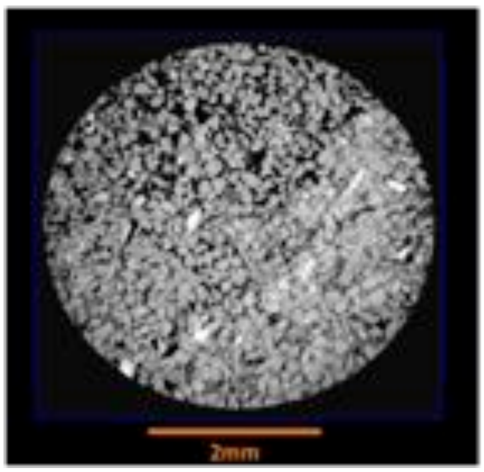
Elastic properties are computed by simulating a static deformation experiment on the vRock digital reservoir rock. The application of stresses to the faces of the sample generates strains in the rock frame that are computed locally using the finite element method (FEM). The resulting effective deformations of the sample are related to the stresses applied at the boundaries to calculate the effective elastic moduli. This application assumes that linear elasticity laws are valid within the sample. Therefore, the elastic moduli thus obtained can be converted into the elastic-wave velocities.

•Results provided: Bulk modulus, shear modulus, Young's modulus, the compressional-wave velocity, the shear-wave velocity, and Poisson's ratio

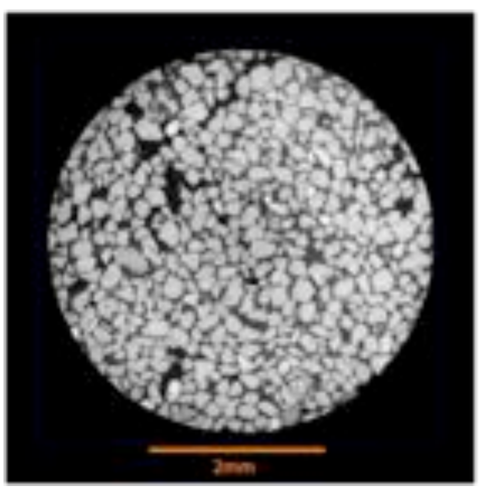
Oil Sands



Oil sand - Canada		
Sample VOB6_a	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	23	30.2
Permeability (mD)		
Avg. Permeability	351.3	462
Formation Factor		
Formation Factor (X)	20	
Formation Factor (Y)	14	
Formation Factor (Z)	15	

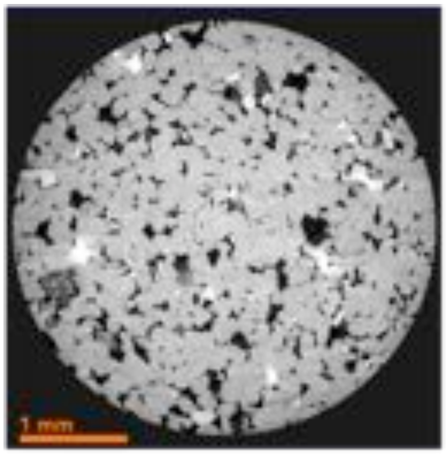


Oil sand - Canada		
Sample VOB7_a	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	29	30.8
Permeability (mD)		
Avg. Permeability	670	385
Formation Factor		
Formation Factor (X)	8.5	
Formation Factor (Y)	9.0	
Formation Factor (Z)	13	

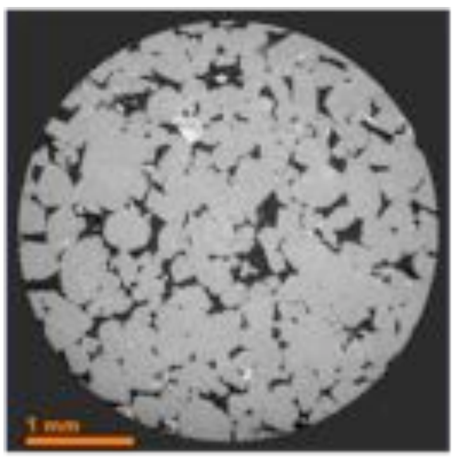


Oil sand - Canada		
Sample VOB10_a	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	38	35.7
Permeability (mD)		
Avg. Permeability	12800	8547
Formation Factor		
Formation Factor (X)	4.5	
Formation Factor (Y)	4.5	
Formation Factor (Z)	4.9	

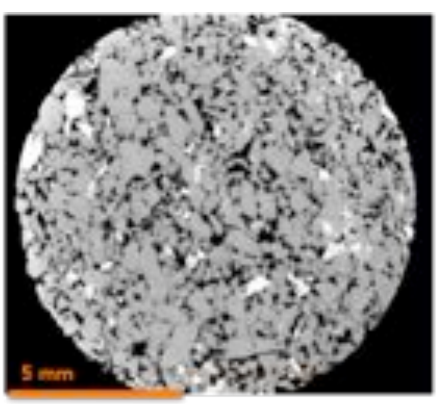
Sandstones



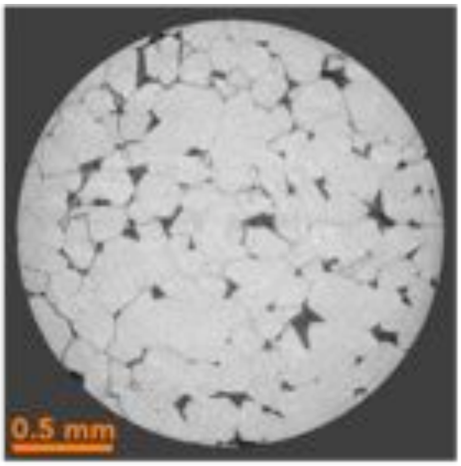
Well consolidated sand - Glaciomarine environment		
Sample 212-4	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	12	12.5
Permeability (mD)		
Avg. Permeability	100	200
Formation Factor		
Avg. Formation Factor	65	40



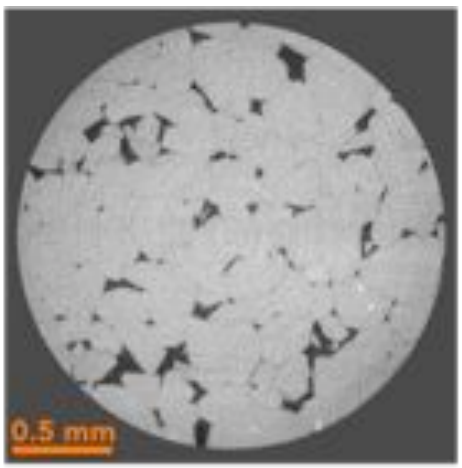
Well consolidated sand - Glaciomarine environment		
Sample 331-5	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	14	14.5
Permeability (mD)		
Avg. Permeability	500	1000
Formation Factor		
Avg. Formation Factor	35	30



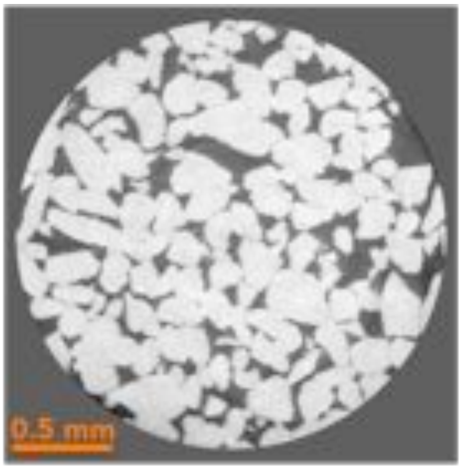
Sandstone- Deep water Nigeria		
Sample A	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	19.8	18.5
Permeability (mD)		
Avg. Permeability	149	251



Fontainebleau sandstone		
Sample A-82	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	7.3	7.6
Permeability (mD)		
Avg. Permeability	7.34	7.08
Formation Factor		
Avg. Formation Factor	147	167
Elastic properties		
Vp (Km/s)	5.458	5.422
Vs (Km/s)	3.715	3.487

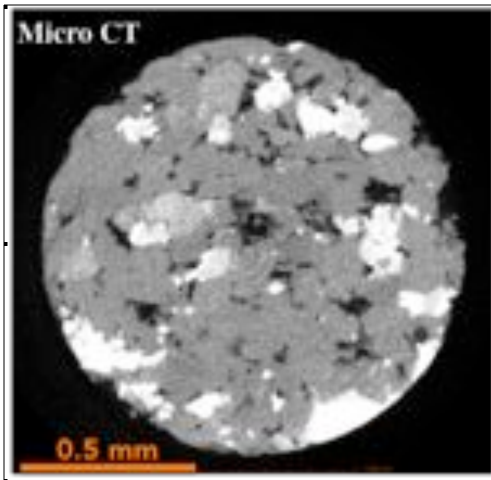


Fontainebleau sandstone		
Sample A-33	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	7.3	7.2
Permeability (mD)		
Avg. Permeability	7.34	12.45
Formation Factor		
Avg. Formation Factor	193	74.68
Elastic properties		
Vp (Km/s)	5.533	5.424
Vs (Km/s)	3.737	3.716

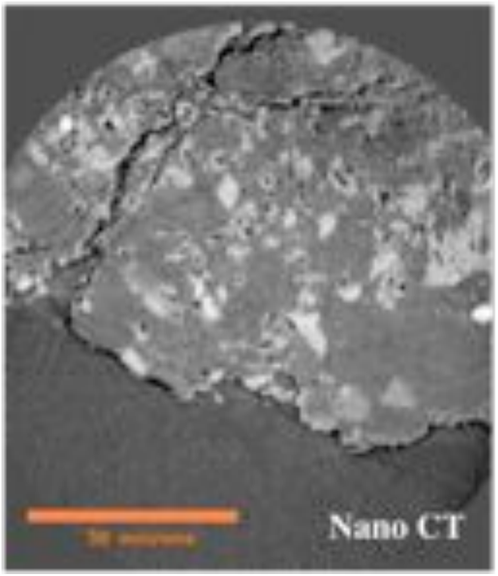


Fontainebleau sandstone		
Sample H-27	Ingrain Results	Physical Results
Porosity		
Total Porosity (%)	23.3	25
Permeability (mD)		
Avg. Permeability	3296	3630
Formation Factor		
Avg. Formation Factor	11.36	3.42
Elastic properties		
Vp (Km/s)	4.025	3.861
Vs (Km/s)	2.679	2.668

Tight Gas Sand

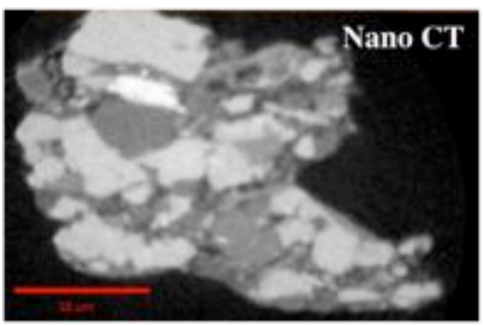


Tight Gas sand - Lower Williams Fork Formation			
Sample 270_1	Ingrain Results	Lab_1	Lab_2
Porosity			
Total Porosity (%)	9.2	11.8	11.06
Permeability (mD)			
Avg. Permeability	3.6	0.0015	0.011

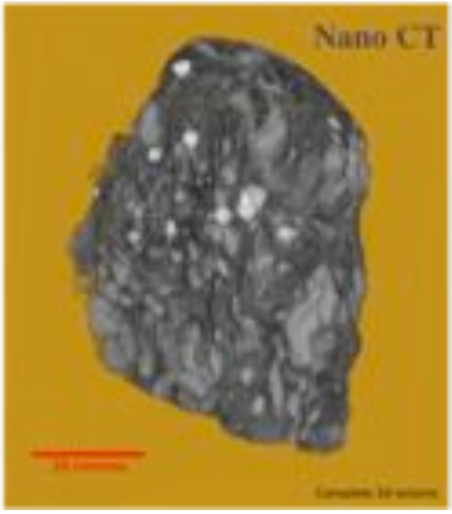


Tight Gas sand - Lower Williams Fork Fm.		
Sample 270_1	**Ingrain Results**	**Lab_1**
Porosity		
Total Porosity (%)	1.3	6.67
Permeability (mD)		
Avg. Permeability	0	0

Shale

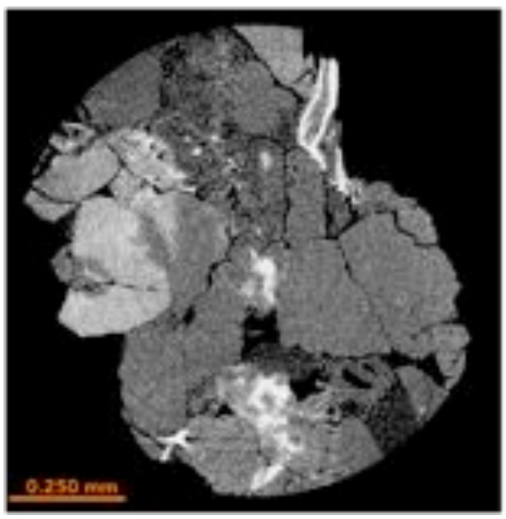


Woodford Shale		
Sample 1-7A	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	2.5	0.9 – 3.82
TOC		
TOC (%)	11	7.22

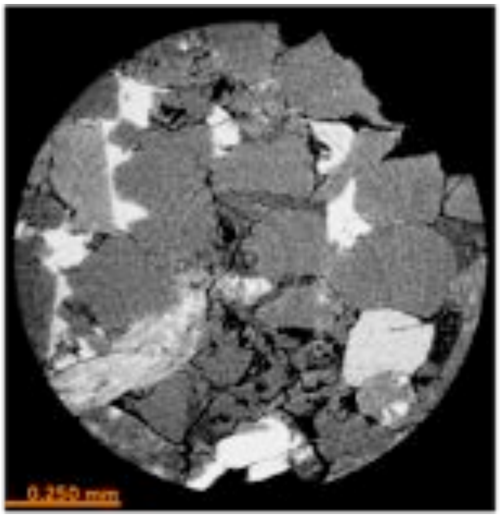


Woodford Shale		
Sample 2-30	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	2.0	0.91
TOC		
TOC (%)	7.6	7.8

Cuttings



Sandstone cutting - Canada		
Sample 480_2	**Ingrain Results**	**Back Scatter SEM Results**
Porosity		
Total Porosity (%)	8.9	9.3
Permeability (mD)		
Directional Permeability (X)	6.02	Not measured
Directional Permeability (Y)	6.19	Not measured
Directional Permeability (Z)	4.81	Not measured
Formation Factor		
Formation Factor (X)	260	Not measured
Formation Factor (Y)	110	Not measured
Formation Factor (Z)	220	Not measured

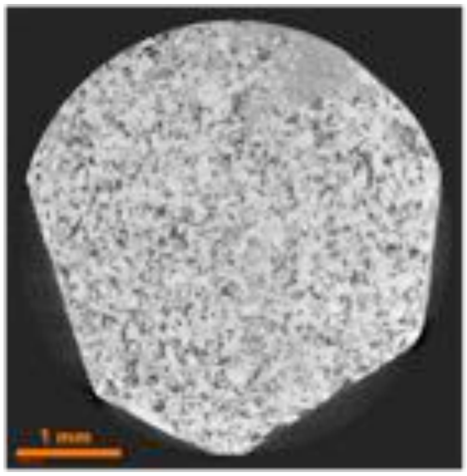


Sandstone cutting - Canada		
Sample 475_3	**Ingrain Results**	**Back Scatter SEM Results**
Porosity		
Total Porosity (%)	7.9	9.4
Permeability (mD)		
Directional Permeability (X)	3.46	Not measured
Directional Permeability (Y)	2.6	Not measured
Directional Permeability (Z)	4.22	Not measured
Formation Factor		
Formation Factor (X)	300	Not measured
Formation Factor (Y)	250	Not measured
Formation Factor (Z)	300	Not measured

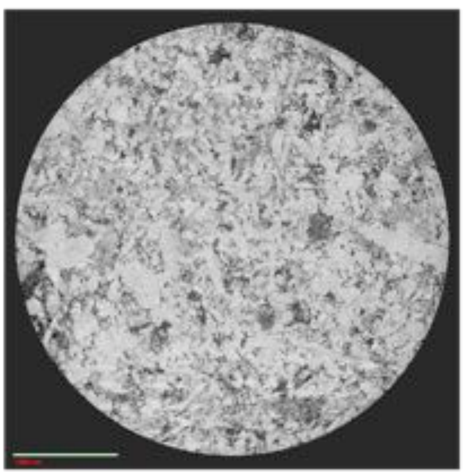
Dolomite cutting - USA	
Sample 1A_2	**Ingrain Results**
Porosity (%)	
Total Porosity	15.3
Connected Porosity	14.1
Permeability (mD)	
Directional Permeability (X)	20.6
Directional Permeability (Y)	37.8
Directional Permeability (Z)	13.4
Formation Factor	
Formation Factor (X)	200
Formation Factor (Y)	94
Formation Factor (Z)	170
Elastic Properties	
Compressional Velocity (Km/s)	5.4
Shear Velocity (Km/s)	3.1
Bulk Modulus (Gpa)	38.6
Shear Modulus (Gpa)	22.4
Young's Modulus (Gpa)	56.3
Poisson Ratio	0.26

This is an example of dolomitic cuttings. No lab measurements were available for this formation

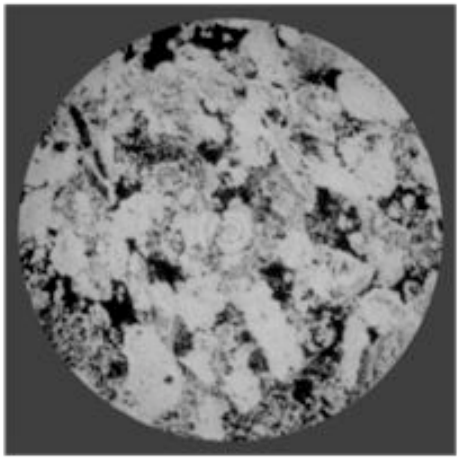
Carbonates



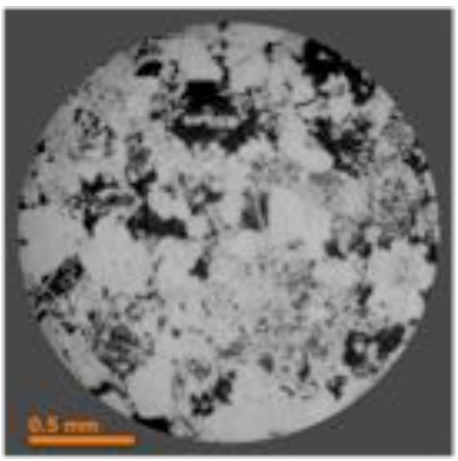
Carbonate - Slope and base of slope environment		
Sample MA_2a	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	28	28
Permeability (mD)		
Avg. Permeability	97.5	135.3



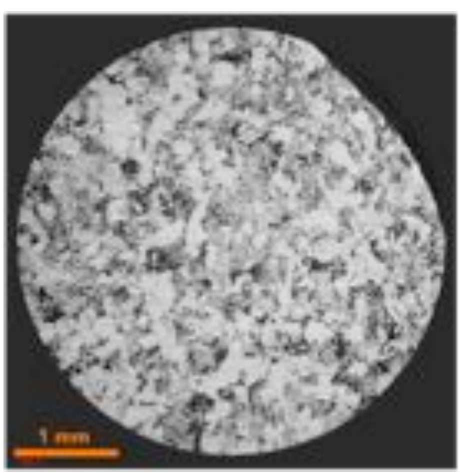
Carbonate – Slope and base of slope environment		
Sample Ma_3b	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	24	26
Permeability (mD)		
Avg. Permeability	168.4	124.7
Elastic properties		
Vp (Km/s)	3.72	3.53
Vs (Km/s)	2.19	2.06



Carbonate – Slope and base of slope environment		
Sample Ma_5a	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	25	25
Permeability (mD)		
Avg. Permeability	85.8	83.5
Elastic properties		
Vp (Km/s)	3.96	3.88
Vs (Km/s)	2.31	2.30

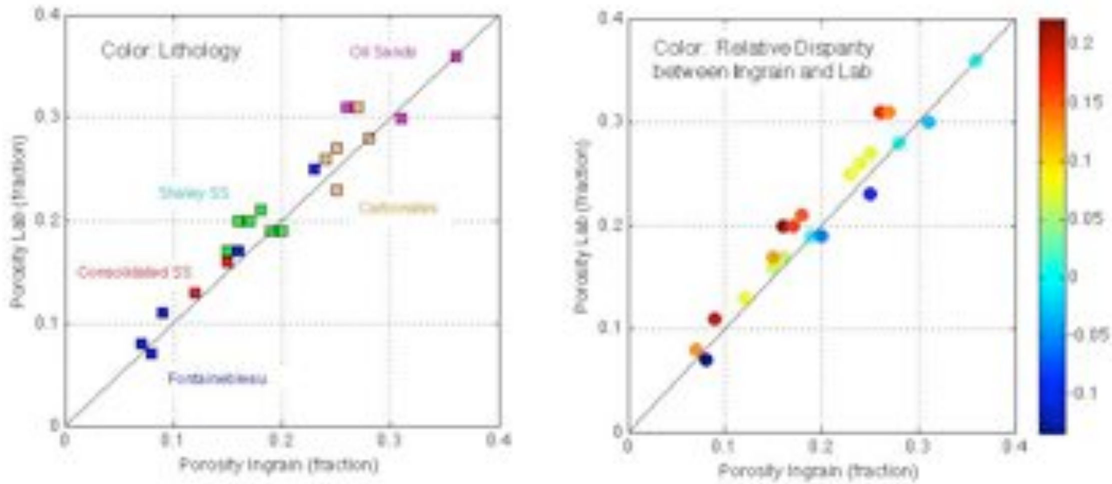


Carbonate - Slope and base of slope environment		
Sample MA_6a	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	25	27
Permeability (mD)		
Avg. Permeability	137.9	128.2

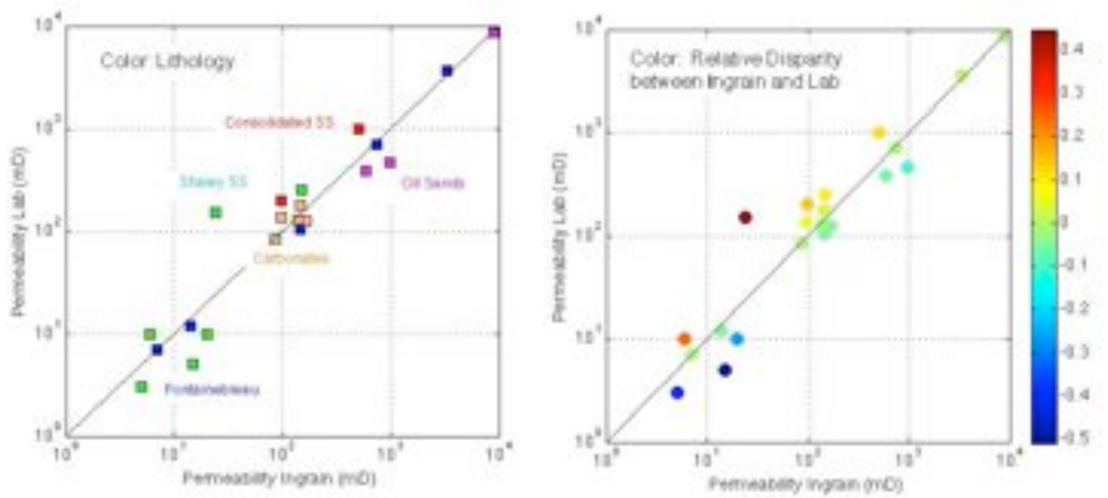


Carbonate - Slope and base of slope environment		
Sample MA_8c	**Ingrain Results**	**Physical Results**
Porosity		
Total Porosity (%)	27	31
Permeability (mD)		
Avg. Permeability	144.9	176.7

Porosity and Permeability results

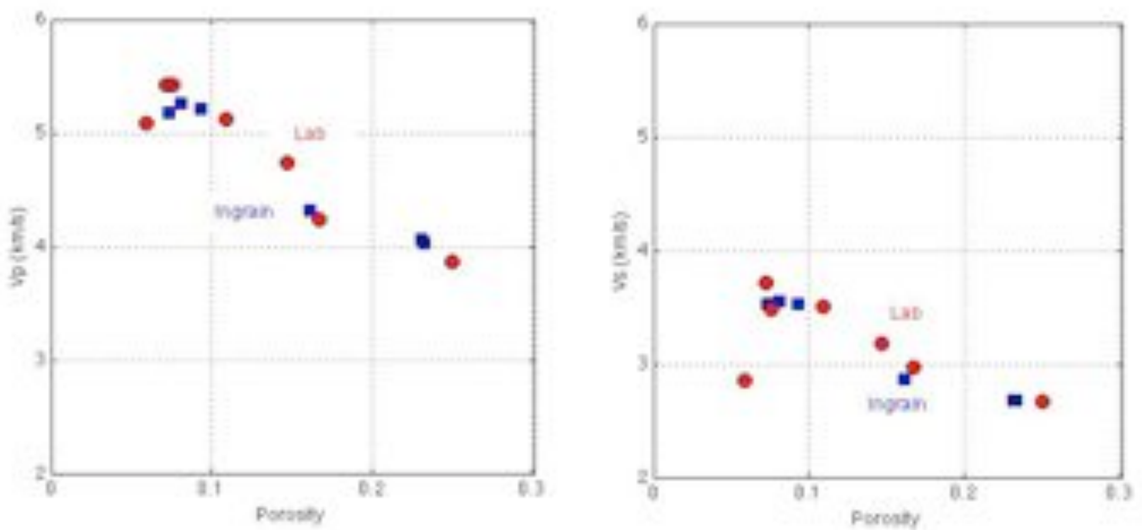


Lab-measured porosity versus Ingrain-computed porosity. Left: different color for different lithology, as shown in the display. Right: color-coded by relative disparity between the Ingrain and lab porosity. This disparity is reasonably small in general. It is larger for shaley sand and carbonates than for other samples as the two former lithologies exhibit larger spatial heterogeneity.

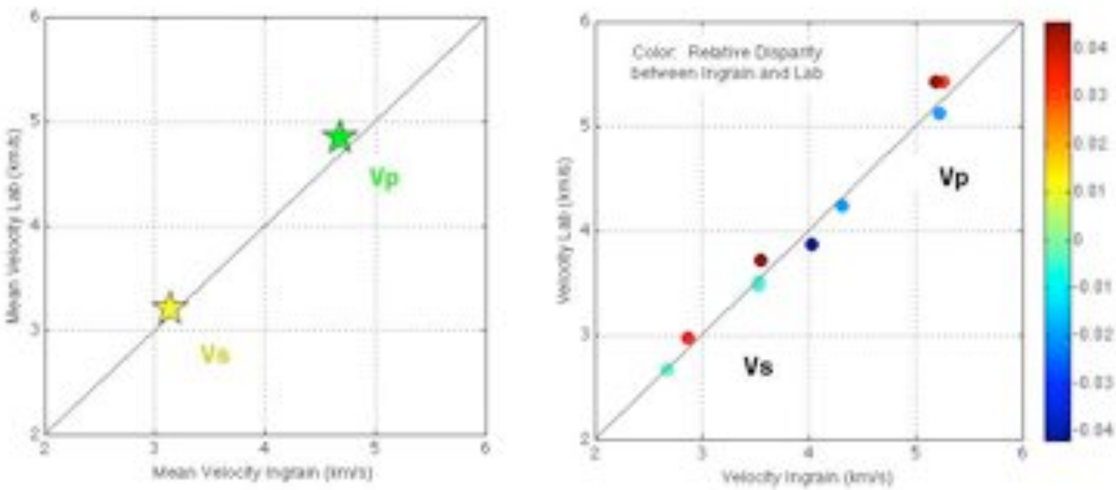


Lab-measured permeability versus Ingrain-computed permeability. Left: different color for different lithology, as shown in the display. Right: color-coded by relative disparity between the Ingrain and lab porosity. This disparity is reasonably small in general.

Elastic properties - Fontainebleu sandstones



Lab-measured velocity versus porosity (red circles) and Ingrain-computed velocity versus porosity (blue squares). Left: the P-wave velocity. Right: the S-wave velocity.



Lab-measured velocity versus Ingrain-computed velocity. Left: mean values for the P- and S-wave velocity. Right: color-coded by relative disparity between the Ingrain and lab data.

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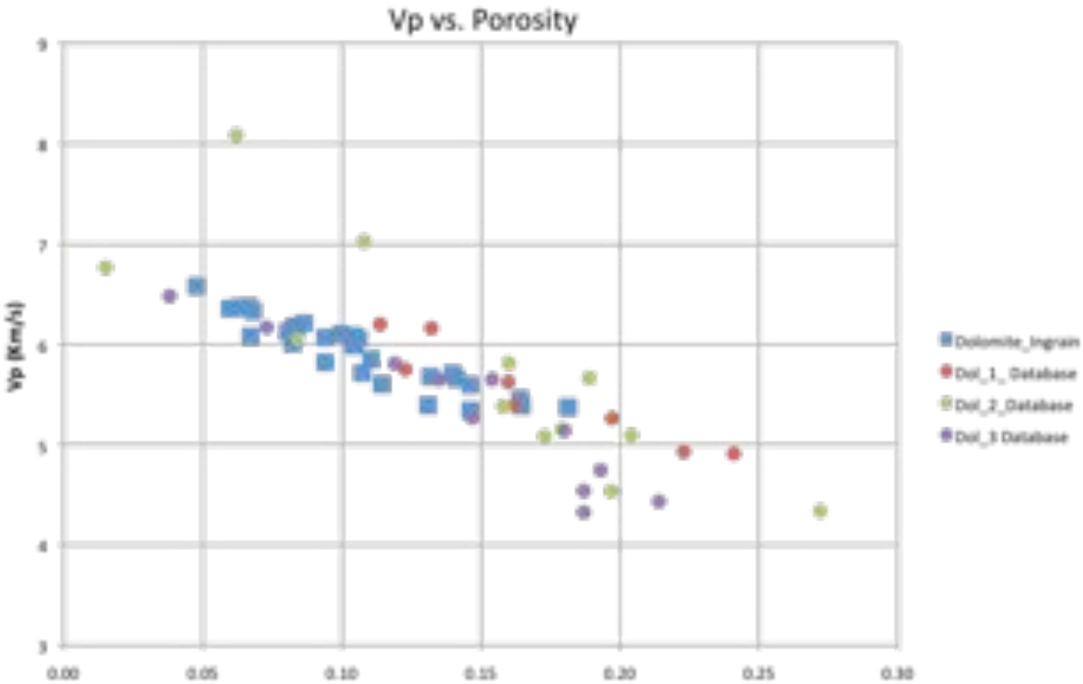
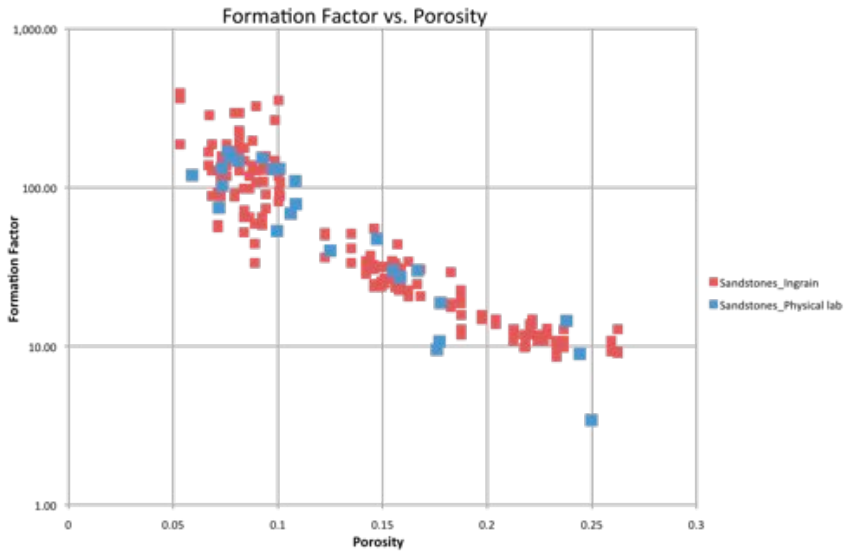
Elastic properties Dolomite cuttings



The company did not have measured velocities on this set of samples. We compare Ingrain computations to Dolomites database.

Electrical properties



Ingrain's Formation Factor is computed on X, Y and Z directions.