An Integrated Approach to Shale Reservoir Characterization Using Digital Rock Physics

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Abstract

Much of the recent understanding how shale reservoirs store and flow hydrocarbons has come from high resolution imaging of very small pores, especially within the kerogen component of shale. The industry was first made aware of the nature of porosity in shales in 200 D9 by the pioneering work of the Bureau of Economic Geology (University of Texas) in Austin. Robert Loucks and his colleagues presented images of Barnett Shale pores obtained with a revolutionary new technology called focused ion beam scanning electron microscopy (FIB-SIM). For the first time, geologists could see that the porosity of shale was unlike anything that had ever been observed previously. Loucks' remarkable images clearly showed that the pores were not only very small (around 1 to 5 millionths of an inch across!) but that virtually all of the porosity in the Barnett was in the kerogen, not in between solid mineral grains like most other oil and gas reservoirs (Figure 1). These important findings have been confirmed by researchers at the University of Oklahoma and Indiana University.

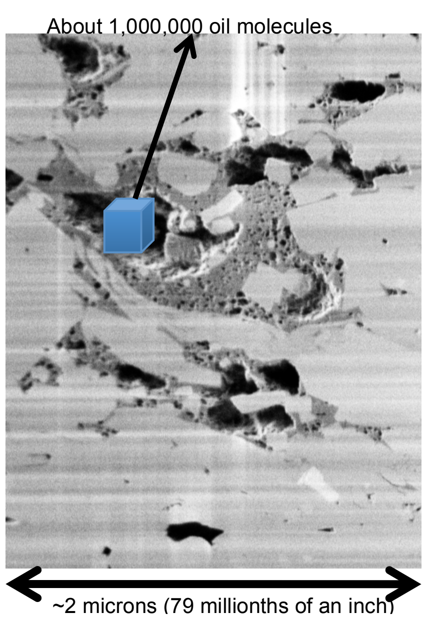

Fig 1: *A 2D, focused ion beam polished, scanning electron microscope (FIB-SEM) image of porosity inside solid kerogen in the Eagle Ford Shale. While the pore sizes are typically a few millionths of an inch (tens to hundreds of nanometers), gas and oil molecules are much smaller. The inset box above is large enough to contain about 1 million oil molecules.*

Of course geologists and engineers need to know much more about shales than just pore size and shape. The most important information is how much porosity is *connected* so that it can provide flow paths for oil and gas, and what is the permeability, or ease with which the hydrocarbons can flow. These needs can be met with another cutting edge technology called Digital Rock Physics (DRP). DRP permits computation of connected porosity, disconnected porosity and directional (X, Y, and Z) permeability from three dimensional pore space images that are created by the latest generation FIB-SEM apparatus. This article describes how Digital Rock Physics (DRP), employing unique and proprietary fluid flow algorithms, has been used by one operator to de-risk exploratory drilling in the Eagle Ford shale of south Texas.

Core samples were tested from two wells in the Eagle Ford. Well A, is in the early o Dil window of the Eagle Ford on the northern edge of the play. Well B, near Hawkville Field, is in the late oil window. Digital Rock Physics was shown to be an effective and expeditious method to characterize this very "tight" (low permeability) formation and provided data that might otherwise have been difficult or impossible to obtain from conventional core laboratory methods.

Objective

The principal objective was to quantify the relationships between porosity and matrix permeability for the key producing facies within the depth zone of interest. Such trends, combined with facies identification from whole core X-ray CT scanning, facilitate upscaling and well to well correlation. A secondary objective was to explore, and quantify if possible, the links between rock layers (how the original shale was deposited) and pore types, which are related to overall reservoir quality.

Geology from three dimensional X-ray CT scans of whole core

The first step of the DRP process for this well began with CoreHD™ calibrated whole core X-ray CT scanning at high resolution (about 500 CT slices per linear foot of whole core), followed by computation of "core logs" for bulk density (RhoB) and effective atomic number (Zeff). These bulk density and Zeff logs, measured on whole core, help discriminate lithology, porosity, rock facies, and depositional sequences. Figure 2 shows how the RhoB and Zeff data can be used to separate the well into multiple facies, and to determine which facies is most likely to be high quality reservoir. In this formation, the lowest density and lowest effective atomic number quadrant of data (green data points) probably represents higher porosity and/or higher kerogen content zones.

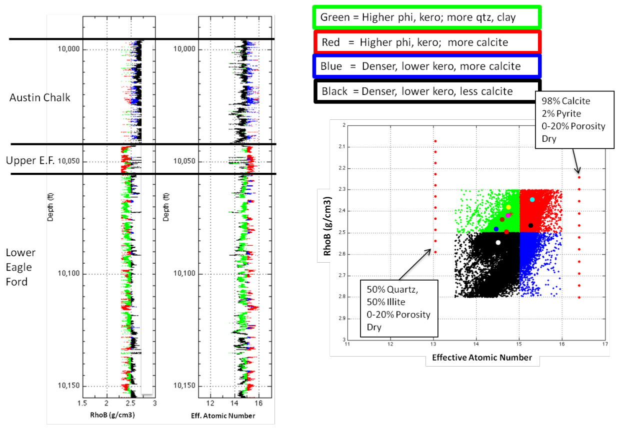

Fig 2: Bulk density and effective atomic number (Zeff) from CoreHD data is used for lithology and facies discrimination, and to aid in upscaling. This data is from Well B.

Shale plug sample analysis with Digital Rock Physics

Plug samples were taken at multiple depths based on whole core scanning and information from the operator about principal zones of interest. Plug sample analysis was used primarily to quantify porosity and kerogen content and to see how much it varied from place to place in the sample (Figure 3). Plug sample analysis was also used as a screening process to ensure representative samples for the subsequent 3D special core analysis (SCAL).

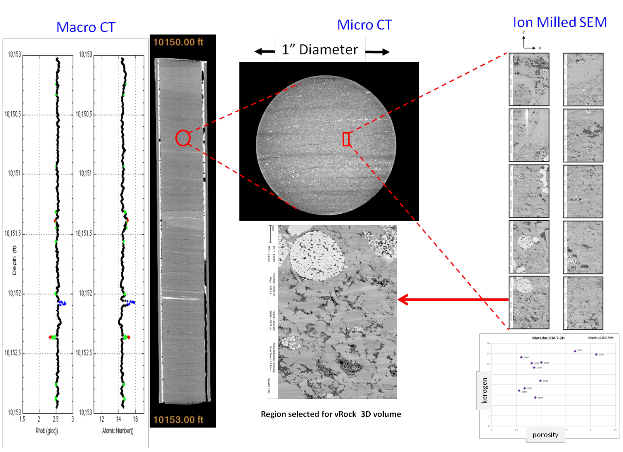

Fig 3: Plug sample selection and analysis process using a combination of CoreHD CT whole core analysis, micro-CT scanning, and quantitative analysis of ion beam polished SEM data (Well B).

Shale special core analysis (SCAL) with Digital Rock Physics

The 3D SCAL analysis began with ultra-high magnification FIB-SEM pore and mineral matrix imaging. Next was segmentation, image processing, and creation of vRock® digital reservoir rocks. This analysis included connected and isolated porosity, kerogen volume fraction and distribution, and absolute permeability in X, Y and Z directions. Other shale data can also be obtained such as two-phase relative permeability and capillary pressure curves.

In this project, a major objective of the process was to understand the relationships between porosity and permeability for each of the primary producing facies. This information (as illustrated in Figure 4) is an important component in shale reservoir characterization. These trends can be integrated with facies logs from CoreHD to improve net/gross, reserves, and producibility estimates. Digital Rock Physics (DRP) will also reveal details of the shale pore types and show which pore types are associated with higher permeability. In Figure 4 it appears that organic matter porosity (porosity associated with kerogen) is especially critical to good reservoir permeability. On the other hand, those samples with more intra-granular porosity appear to have lower permeability for a given porosity. DRP results (large square symbols) also indicate that where there is sufficient kerogen and porosity associated with kerogen, there is also ample permeability for oil production from multi-stage hydraulically fractured wells.

Conventional core analysis methods tends to show lower permeability than the DRP results in the lower porosity range, but the trends appear to converge at higher porosity (Figure 4). Conventional "GRI" type perm data is shown by small diamond-shaped symbols. This difference in porosity-perm trends between the two methods will be the subject of further study.

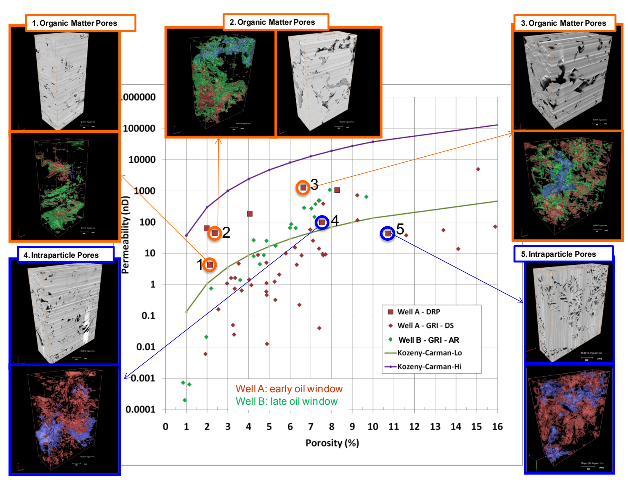

Fig 4: Organic matter (kerogen) dominated samples have better permeability than samples with equivalent "conventional" porosity between solid grains. Special core analysis from 3D FIB-SEM imaging and vRock computation can help relate facies and shale pore types to porosity-permeability trends. These trends can

then be integrated with facies logs from CoreHD to improve net/gross, reserves, and producibility estimates.

Conclusions

In this experimental study we have conducted Digital Rock Physics (DRP) analysis on whole core and plug samples from two wells in the Eagle Ford formation. The following observations can be made;

- Density and effective atomic number (Zeff) from high resolution X-ray CT scans of whole cores provides detailed information on layering and facies in the Eagle Ford shale.
- Key facies changes can be readily observed from the CoreHD data, while the core is preserved in the sealed aluminum tubes.
- Plug sample locations can be selected based on key facies and lithology variations from whole core scans.
- Pore types are mainly organic matter and intra-granular.
- At higher porosity, organic matter dominated samples have better permeability than comparable porosity samples with intra-granular porosity.

Acknowledgments

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