Digital Rock Physics for Reservoir Characterization

Maria R. Ceron[1], Juan F. Martinez[1], Elizabeth Diaz[2], Joel Walls[2], Carl Sisk[2]

1. Agencia Nacional de Hidrocarburos (ANH). Bogotá, Colombia
2. Ingrain Inc. Houston, TX, USA

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Introduction

The Agencia Nacional de Hidrocarburos (ANH) is responsible for structuring and promoting opportunities for exploration and exploitation of the Colombian subsoil. The agency also assumes functions that emphasize the management of those resources, and proposes studies and research in the areas of geology and geophysics to generate new knowledge in the sedimentary basins of Colombia. The objectives are to evaluate and realize the potential of hydrocarbons as well as to optimize the use of the resources.

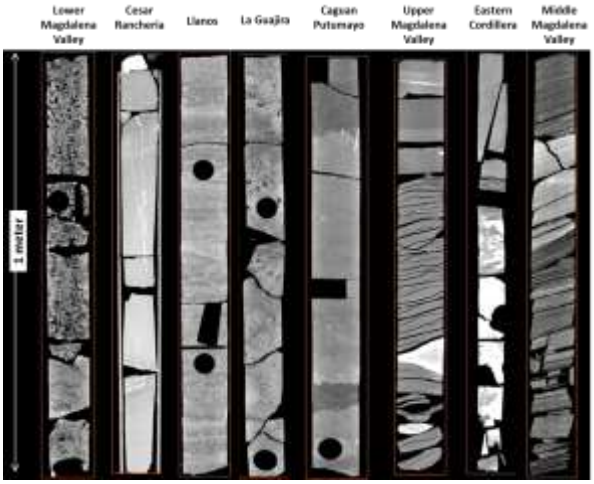

Figure 1: Examples of vertical X-ray CT slices of whole core samples extracted from 3D volumes.

Fulfilling its mission and strategic objectives, the Technical Subdivision of the ANH is currently digitizing and archiving all core samples stored in the national core repository “Bernardo Taborda”, which exceeds 370,000 feet of core coming from about 1,840 wells, and represents the most valuable physical record of the drilling and exploration activity of the country.

A rapidly emerging technology called Digital Rock Physics (DRP) is being utilized for this ambitious project. This will generate a digital database that: 1. preserves an enormous volume of information, 2. gives added value to existing information such as well logs and seismic data, 3. supports research and collaboration, and 4. provides new information for the exploration of conventional and non-conventional plays. Figure 1 shows examples from different wells and basins.

The X-ray CT imaging of the entire core record of a country is a milestone in the history of core analysis. These 3D image volumes by themselves constitute a unique and valuable catalogue. The CT imaging is being performed with a dual-energy process, allowing for a continuous computed log of high resolution Bulk Density (RHOB) and photo-electric factor (PEF) for each piece of core.

Figure 2 shows an example of a section of core fully imaged in 3D at a resolution of 625 microns per vertical slice. This visual data combined with the quantitative information will become a powerful database for the main current and future source of information for the oil industry in the country for both conventional and unconventional resources.

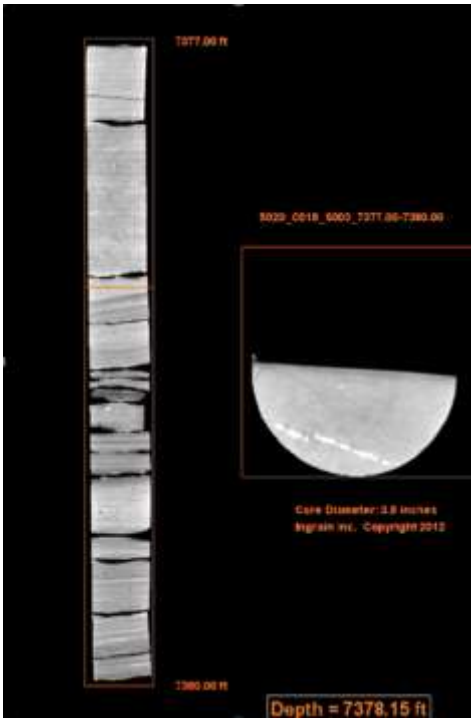

Figure 2: Example of image results from scanning of one meter of slabbed core.

Method

Digital Rock Physics workflow (Figure 3) starts with a non-invasive, dual-energy X-ray CT scan of the core followed by computation of bulk density and effective atomic number along its length (Stage 1). This data helps geologists identify the natural variations at a scale several times finer than open-hole well logs.

In Stage 2, plug samples are taken at multiple depths based on whole core imaging in Stage 1. Each plug sample is imaged with a high resolution X-ray method followed by a unique SEM analysis which provides porosity and organic matter volume fraction and is also used as a screening tool to ensure representative samples for the subsequent Stage 3 pore scale analysis of connected porosity and permeability in horizontal and vertical orientation. Fundamental principles and examples of this technology for unconventional resources are discussed in Keehm, et al., 2001, Tolke et al., 2010, and Walls, et al., 2012.

After all digital data are collected and processed, more advanced analysis is performed to examine the relationships between various rock properties such as organic content, porosity, and directional permeability. These results are then used for upscaling back to well log and reservoir scale.

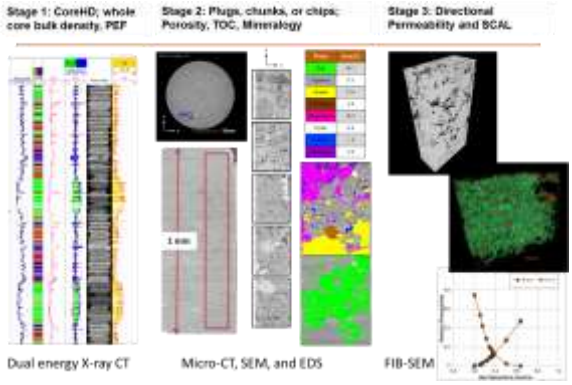

Figure 3: Digital rock physics workflow for shales and other unconventional resources. Duel energy X-ray CT imaging is used for lithology, facies, and parasequences discrimination, and to aid in upscaling.

Results

During the implementation of this project approximately 9,500 meters of core were digitized from 140 wells that are mostly located in the Llanos Basin, Catatumbo Basin, and Middle Magdalena Valley. From this whole core, 4,500 plug samples were taken for Stage 2 analysis and 450 were selected for Stage 3 analysis of connected porosity and permeability (Figure 4).

Integration of these results together with petrophysical evaluation allowed the high grading of the geological sequences with more potential for unconventional reservoirs. From the data obtained by digital rock physics plus integration of well logs, seismic and other types of data, three Basic Studies were prepared for the Llanos, Catatumbo, and middle Magdalena Valley. Some of these results and reports are now available from the ANH website and all of the data will become available for downloading in the future. ANH plans to continue with this project in order to implement a digital Litoteca easily accessible to the public.

Observations and Conclusions

Based on the analysis of this data so far we can state the following;

- Rock quality of La Luna (VMM and Catatumbo) is similar to or better than many North America shale plays.
- Gacheta formation in Llanos may be prospective but data is limited.
- Rock quality compared to analogs.
  - La Luna, Catatumbo: TOC higher, porosity slightly lower, perm higher than Wolfcamp or Lower Eagle Ford.
  - La Luna, VMM: Porosity similar and permeability higher than middle Wolfcamp.
  - Gacheta, Llanos: Porosity and permeability similar to Fayetteville.
- All formations show large variability by depth and well location.
- Tier 1 Unconventional Prospect: LaLuna; Catatumbo and VMM
- Tier 2 Unconventional Prospect: Lower Gacheta; Llanos
- Formations with good potential but limited data: Tablazo (VMM), Capacho (Catatumbo), Paleozoic sequence (Llanos).

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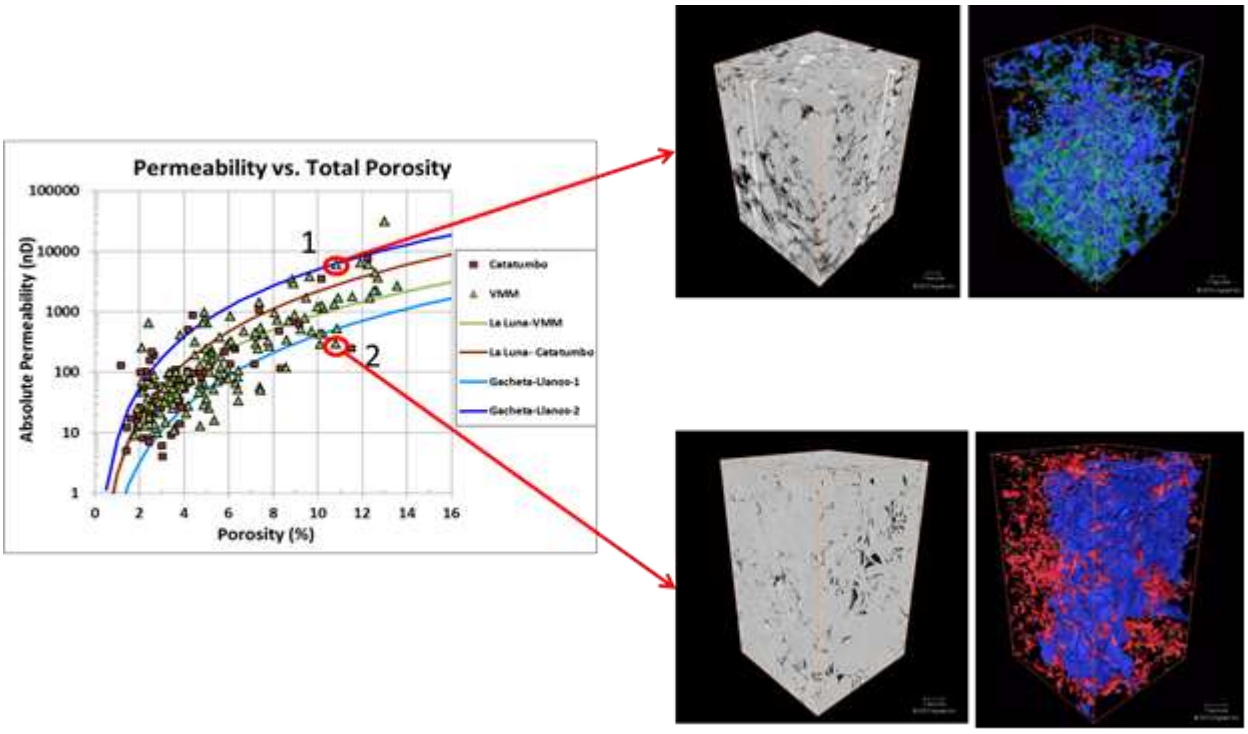

Figure 4: Samples 1 and 2 have similar porosities, but their horizontal permeability values differ. Sample 1 contains more organic porosity and is connected through the organic material. This sample has the higher permeability. Sample 2 contains mostly inter-granular porosity and has much lower permeability. Images on right show 3D view of connected porosity (blue), isolated porosity (red), and solid organic material (green).