Reservoir Performance Evaluation by Cost Effective Digital Petrophysics Workflows

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Aims and Motivation
Digital Petrophysics Characterization (also Digital Rock Physics/Analysis in the literature) has been a technology breakthrough for the Oil & Gas companies’ exploratory efforts (Zalam, 2012). Reservoir modeling and performance forecasting require a vast amount of information in order to make more educated decisions. Biased spatial sampling, insufficient amount of data and usually long periods of time for a comprehensive core analysis campaign can obscure and/or delay critical information to the decision makers. Recent advances in X-Ray micro-tomography, computational hardware and numerical simulation software have opened a possibility to obtain this information from realistic digital rock images (not through approximate rock physics models but direct representation of the pore space). Due to their digital nature these tasks could be conducted in fractions of the cost and time and also from rock materials generally non suitable for conventional lab testing like drill cuttings (Tono, 2008) increasing spatial sampling and reservoir properties data quantity. Such capacity could effectively enhance our ability to deliver faster and more information to exploration and production managers. Since its early development stage, this technology has been tested against the experimental protocols with very good statistical agreement (i.e. Knackstedt, 2004) However, this new technology is still complex, expensive and conducted by a reduced group of specialists. The aim for this work is to present a simplified workflow which can produce meaningful inputs for rock typing and reservoir characterization using a set of hardware/software tools with the highest value/cost ratio currently available and with the possibility to be conducted in reasonable short periods of time by non-expert personnel. Based on these requirements, the presented workflow was designed for massive deployment campaigns to keep this technology relevant during low O&G Capex environments.

Method
A conventional siliciclastic asset was selected to design and perform the presented methodology. The protocol is divided in 3 stages resembling standard geophysical prospecting surveys:

- Imaging: Data Acquisition from X-Ray Micro-Tomography.
- Processing: Image enhancement, solid and pore phase separation (segmentation), meshed pore space representation.
- Characterization: Pore space morphometric analysis and interpretation and absolute permeability numerical simulation by Finite Element Analysis (FEA).

It was conducted in two phases: 1) Pilot test for standard laboratory comparison and protocol fine tuning and 2) Full workflow performance on field samples. A detailed explanation of the protocol stages and phases can be found next.

**Imaging:** The selected X-Ray Micro-tomographer was the Skyscan 1272 with an 11Mp camera. This option allowed imaging 3mm-5mm radii sub-plugs completely inside the FOV with enough resolution to map almost entirely the pore structure present in the rock and
controlling transport properties on it. Such a configuration will suit most of the conventional reservoirs rock samples regarding representativeness of the analyzed volume as it will be bigger than these properties correlation (homogeneity) lengths associated with granular random disordered media like rocks (Garcia, 2004).

The acceleration voltage selected was around 80kV-100kV, allowing enough photon transmission through the denser samples. It is important to observe than in geomaterials (relatively low atomic number (Z)) it is advisable to keep energies lower than 100kV to improve image contrast. The interaction of electromagnetic radiation with matter will mainly follow 3 phenomena: Photoelectric Effect, Compton Effect and Pair Productions (as Pair Production and other interactions need higher energies than the ones encounter in lab based systems they will not be considered here). The photon probability to be absorbed is proportional to $Z^3$ for the Photoelectric Effect and to $Z$ for the Compton Effect (Als-Nielsen, 2001). As geomaterials exhibit a very short range in density variations Photoelectric Effect’s superlinear proportionality with Z will enhance the transmission contrast during X-Ray scanning compared with the Compton’s Effect linear proportionality.

Regarding acquisition parameters, all jobs were designed as overnight 360° (with $\Delta\theta=0.2$) scans (11-13hrs). Resolution varied between 1µm and 3µm isotropic voxel size depending on the rock sample. As the actual rock materials were not RCAL/SCAL suitable, 2mm-5mm diameter subplugs were extracted from original cleaned material and mounted on a vertical column for scanning. In order to increase the signal/noise ratio (which was very low in 1 frame scans) an 8 frame averaging was used.

**Processing:** After proper image reconstruction, the Custom Processing CTan software modules were used. A subtle Gaussian filter combined with a Conditional Mean filter provided fairly good results for image denoising. For image segmentation (Figure 1, left and middle) an adaptive approach was used. The limits for such filtering were set within the grayscale values were voxels exhibit higher uncertainty on phase character due mainly to the partial volume effect (Figure 1, right).

![Figure 1: (Left) Original Dataset, (Middle) Filtered and Segmented Dataset, (Right) Grayscale Histogram showing “uncertain” voxels range.](image)

Once the pore phase was segmented and cleaned, the resulting B&W image stack was used as an input to the ScanIP (Simpleware Inc.) software environment. The B&W image was processed to label the solid and fluid domains. The +FE add-on module was used for mesh generation. Mesh quality and continuity in complex surfaces can be an important issue when dealing with pore throats. In order to get an efficient commitment between mesh quality and elements number, an adaptive and progressively decimated (or refined) mesh from the image resolution was obtained. Several decimations were tested (Figure 2, +FE Free -10, -50) from the automated finest mesh algorithm (Figure 2, +FE Grid). These tests were used to balance mesh quality with the amount of elements which could be processed using actual computational hardware in reasonable times (Overnight runs).
Characterization: Petrophysical properties were estimated after image processing from 2 sources: 1) Morphometric Analysis and 2) Numerical simulation (FEA).

1) Morphometric Analysis: From the segmented pore space several 3D parameters were measured:

- Total Porosity in percentage (pore voxels/total voxels ratio).
- Pore Size Distribution by thickness measurements using largest spheres inscribed (Hildebrand 1997a)
- Fractal Dimension (FD) using the Kolmogorov or “box counting” method.
- Structure Separation (SS): Single mean from pore space thickness measurements.
- Connectivity Density (Euler-Poincare number) (CD): Quantify the degree to which a structure is multiply connected. It is a measure of how many connections in a structure can be severed before the structure falls into two separate pieces.

Porosity and Pore Size distribution are standard properties measured in the lab as they represent important petrophysical characteristics of reservoir rocks. Pore sizes can be very useful to estimate capillary pressure curves and permeability (Washburn, 1921, Pittman, 1992) which influence actual reservoir performance. FD, DD and CD were calculated as they should be strongly related with reservoir properties and represent a very interesting vector space for rock typing as they should be linearly independent by origin.

2) Numerical Simulation (FEA): Absolute permeability tensor was calculated using a full finite element analysis on the meshes obtained during the processing phase. Mesh and solver parameters were also designed to be conducted during overnight runs (12 hours approx., however, optimized workflows can be run in around 3 hours using the same hardware).

An important quality check performed during numerical simulations is the Representative Elementary Volume (REV) characterization. Progressive sub volume sizes are tested against estimated property, in this case absolute permeability. An asymptotic behavior is expected during sub volume size increasing to define a volume on which the estimated property is no longer dependent of its size (Al-Raousha, 2010). During all samples analysis this procedure was conducted in order to assure that the obtained information is representative enough from the obtained digital model.

As observed in Figure 3 the possible outcome from this analysis can help to identify if the imaged volume was not big enough to capture the properties at plug scale (Region of Interest too small) and to optimize numerical simulation times as smaller meshes can be selected to decrease computational costs (region of Interest too big).
Figure 3: REV analysis workflow. After meshing and initial solver performance a progressive sub volume vs. permeability chart is obtained to characterize property size dependency. Asymptotic regions from this function can help to check digital sample volume representativeness and to optimize computation times.

Results

As previously stated this work was segmented in two phases: 1) An initial pilot test and 2) A full deployment of the protocol designed in 1).

Pilot Test:

In order to obtain an approximate understanding on the protocol implementation and accuracy, one representative sample was chosen. It is important to remember this work was an actual ongoing exploration project and time lapses were an important concern during its execution. A more detailed and extensive analysis about digital petrophysics and its reliability on reservoir properties prediction has been conducted and will be informed somewhere else.

An irregular non RCAL suitable sample was taken, for imaging purposes (Axial rotational symmetry and FOV vs resolution ratio) a cylindrical sub-plug was taken from it and scanned at 4µm resolution (Figure 4)
A “sibling” sample taken from less than one foot away from this one was RCAL suitable and porosity ($\phi$) and permeability ($\kappa$) measurements were taken from it. Both samples by direct inspection belong to the same lithotype and possess the same textural characteristics. The experimental results gave the following numbers: $\phi = 20.7\%$ and $\kappa = 644.01\text{mD}$. Those are the target values to be compared with. After image analysis and FEA fluid flow simulation, the digital obtained results were: $\phi = 21.76\% \pm 1.2\%$ and $\kappa_{zz} = 624.4\text{mD}$. As can be observed, a strong value agreement for lab and digitally obtained RCAL properties was achieved using this workflow.

**Protocol Implementation:**

10 samples from an active asset were selected by field personnel to be analyzed using digital petrophysics technology. All samples were not suitable for conventional laboratory protocols and certainly could help to fill data gaps in specific wells intervals. Subplugs were taken from all of them with radii varying depending on rock textures and fabrics. The results obtained after micro tomographic scans, image processing, morphometric analysis and FEA absolute permeability the simulation are exhibited in Table 1.

<table>
<thead>
<tr>
<th>ID</th>
<th>Total $\phi$</th>
<th>$\phi$ Closest Data</th>
<th>Est. $\kappa$ (mD)</th>
<th>FEA $\kappa$ (mD)</th>
<th>$\kappa$ Closest Data (mD)</th>
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<td>1</td>
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<td>3</td>
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<td>20.6</td>
<td>$[45.22&lt;\kappa&lt;107.8]$</td>
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</table>

Table 1: Digitally obtained porosity and permeability values for the complete 10 samples batch. First column is the ID tag for each sample. Second one is the total porosity obtained from image analysis. Est. $\kappa$ is the permeability range estimated from pore size distributions models (See text for details). FEA $\kappa$ is the permeability from numerical simulation. Closest data columns refer to the closets available RCAL data (which does not imply similarity to the actual analyzed rock)
The complete 10 sample batch was analyzed and RCAL information was obtained. In Table 1 they are exhibited and compared with the closest RCAL information. This information came for the closest RCAL suitable plug available which did not necessarily match the digitally analyzed rock sample characteristics. This comparison was done just to get an approximate idea about lithofacies changes in the well intervals, not to observe a 1 on 1 direct property estimation.

The estimated k column in Table 1 (4th one) contains an estimated range for permeability based on Pittman-Windland models (Pittman, op, cit). The critical radii value was taken from cumulative pore size distributions diagrams like the one showed in Figure 5. This information is a byproduct of the thickness separation analysis conducted during the 3D morphometric analysis.

![Figure 5: Pore size distributions cumulative frequency chart obtained from 3D thickness separation morphometric analysis. Critical radius for Pittman/Winland models was taken from this curve.](image)

Other useful application from 3D morphometry is the possibility for reservoir rock typing beyond conventional Flow Zone Indicators (FZI) which relies on direct measurement and combination of porosity and permeability (Amaefule, 1993). At least locally, at plug or sub-plug scale the properties mentioned earlier FD, SS and CD should be directly related to reservoir performance. FD in rocks is a not an integer number which implies a self-similarity level and also the degree of spatial isotropy or structural “smoothness”. The more complex the rock (higher FD) the more difficult for the fluid is to go through the structure (lower permeability). Relationships between FD, tortuosity and permeability can be found in (Feranie et al. 2011 and Vadapalli, 2016). SS and CD are more intuitive and straightforward to interpret and to relate with reservoir performance.

In order to validate these relationships with actual reservoir performance, those 3 morphometric parameters were considered as a vector space and the values for each sample were scattered in a 3D graph (Figure 6). 2 distinctive families were identify (Red and grey circles) and grouped together. With the digitally obtained information and data from closets neighbors, the Reservoir Quality Index (RQI, see Amaefule, op cit), a standard reservoir performance quantity was calculated. The two groups exhibited a strong separation in RQI values which evidenced the rock typing power of this morphometric parameters combination.
Figure 6: 3D scatter plot from morphometric parameters. 2 distinctive groups were clustered. Separation in this vector space strongly correlated with actual reservoir performance quantity RQI (see text for a more detailed description). Higher RQI values possibly imply better reservoir performance.

**Conclusion**

Digital rock characterization has a great potentiality to increase our ability to reduce reservoir uncertainty by increasing the amount of information we can get from subsurface rock samples. In this work, using a tabletop micro-tomographer, built in everlasting image processing software licenses, a personal windows workstation and commercially available easy to use FEA software, a fast and economic digital RCAL campaign was conducted. Pilot test gave good agreement with laboratory RCAL data. Full implementation on field samples was done in about 1sample/day rate and with around 3.5hrs/man per sample. Morphometric analysis exhibited an important contribution for pore space characterization, permeability prediction and for reservoir performance rock typing.

New advances in fast micro-tomography could lead to a 10min-1hr scanning times (Sasov, 2016). Even when parameters from these images like s/n ratio and contrast are not as good as longer scanning images, it is important to remember than the product from this phase is a segmented pore space 3D model not a descriptive picture. This fact together with optimized simulation algorithms and IT hardware improvements could lead to massive digital petrophysics campaigns, making this technology readily available for extensive use at industrial production level even at low Capex/Opex environments at least for conventional reservoirs with flow controlling pore space features above MicroCT resolution capacity.
References:

4. García et al, “P-Wave Velocity-Porosity relations and homogeneity lengths in a realistic deposition model of sedimentary rock” Waves in Random Media 14, 129, 2004