CARBONATE RESERVOIR ROCK TYPING AND THE LINK BETWEEN ROUTINE CORE ANALYSIS AND SPECIAL CORE ANALYSIS

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ABSTRACT

Reservoir Rock Types (RRT) are critical factors in reservoir characterization and are one of the most challenging subjects in carbonate reservoirs. One goal of reservoir rock typing is to identify hydraulic units that have similar fluid flow properties. Amaefule [1] introduced a method to determine rock types based on the Flow Zone Index (FZI), which represents a mean pore throat size in microns, derived from the Kozeny-Carmen equations [2,3] with porosity and permeability as the key parameters.

The flow zone index (FZI) technique is applied in this study on a data set of cores from over fifty carbonate reservoirs throughout the world, and representing a wide range of porosity, permeability and mineralogy. This paper describes a new concept with the definition of FZI ranges using key permeabilities at 10%. The fifty carbonates rocks are classified in five FZI reservoir rock types showing similar reservoir properties such as Capillary Pressure, Irreducible Water Saturation and Residual Archie's Parameters m.

INTRODUCTION

This study aims to classify fifty carbonate rocks, twenty-two limestones and twenty-eight dolostones, into classes of reservoir rock types using the flow zone index or FZI method [1, 2, 3]. These carbonate samples present high degree of heterogeneity in terms of texture and petrophysical properties. The formations correspond to various marine depositional environments and have also been subject to diagenesis. Horizontal and vertical plugs were selected for Routine Core Analysis (RCA), mineral volumes (XRD), Mercury Injection Capillary Pressure (MICP), air brine capillary pressures, relative permeability, NMR and dielectric measurements.

FZI MODEL BUILD UP: AN INNOVATIVE CONCEPT DEFINING FZI RANGES ON MICP-RCA

1. Flow Zone Index (FZI) principle

The Flow Zone Index method [1], based on the modified Kozeny-Carmen equations [2,3] and the concept of mean hydraulic radius is calculated using the three equations:

(1) $RQI = 0.0314.\sqrt{\frac{k}{\phi}}$ (2) $FZI = \frac{RQI}{\phi_z}$ (3) $\phi_z = \frac{\phi}{1-\phi}$

Where, RQI is the rock quality index (µm), k is permeability (mD), Ø is effective porosity (v/v), Øz is normalized porosity, and FZI is the flow zone index (µm).

These equations indicate that for any rock type, a log-log plot of RQI versus normalized porosity should yield straight lines with unit slope. Consequently, each line or regression links the permeability to the porosity by a transform and defines a FZI mean, the main parameter of a RRT. By principle, FZI method has two unknowns:

- ✓ The number of regressions that clusters the data and corresponds to the number of reservoir rock types.
- ✓ The slope of the regression that defines the permeability-porosity relationship for each rock type.

2. Innovative approach to solve the two unknowns of the FZI technique

To solve for the optimal number of reservoir rock types:

The optimal number of reservoir rock types is determined using unsupervised neural networks and Self Organized Map (SOM) with capillary pressure curves main parameters (entry pressure, Pd, hyperbole tangent coefficients), water saturation, core permeability and porosity as inputs (figure 1). Results show that five groups should describe best the distribution of the fifty carbonate samples. The FZI model is therefore built on five clusters along five regression lines.

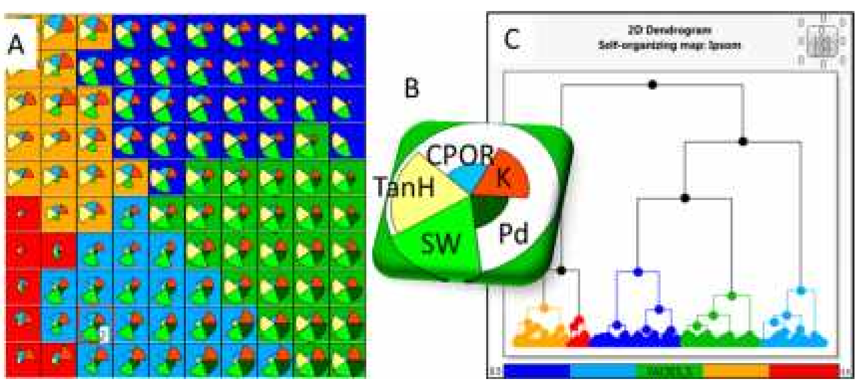

Figure 1: A/ Unsupervised neural network Self-Organized Map (SOM) with 100 nodes (B) clustered in five groups. B/ A node or rose diagram displays five sectors representing normalized input data from RCA and MICP (CPOR, Kair, MICP Pd entry pressure, SW, hyperbole tangent coefficients). C/ 2D dendrogram indicates that five groups are enough to discriminate the input data set.

To solve for the regression and derive the permeability-porosity transform:

The new method is based on FZI ranges calculating with key permeability values at 10% porosity. Each permeability value (0.1, 1, 10, 50, 100mD) was chosen for reasons due flow properties at the core and log scale and suitability in EOR treatments.

Key permeability values are:

- 0.1mD: traditional low end cut-off for reliable permeability log and core measurements. It defines RRT 1 (dark green) with FZI below 0.3µm.
- 1mD: prop. fracturing preferred for carbonate stimulation with less than 1mD in permeability. It defines RRT 2 (green) with FZI between 0.3 and 0.9µm.
- 1-10 m: acid fracturing preferred for carbonate stimulation with permeability from 1 to 10mD. It defines RRT 3 (light green) with FZI between 0.9 and 3µm.
- 10-50mD: acidizing preferred for carbonate stimulation for carbonates with more than 10mD in permeability. It defines RRT 4 (light orange) with FZI between 3 and 6µm.
- >100mD: range where end effects are minimal when doing centrifugation experiments (Rel Perm, PC, *etc*). This could be significant when correlating FZI data to SCAL measurements done with centrifuge. It defines RRT5 (dark orange) with FZI between 6-9 and 9-12µm.

Ø %	K (mD)	RQI	FZI mean	FZI ranges	RRT
10	>100	0.99	9	>6	5
10	10-50	0.70	3.89	3-6	4
10	1-10	0.31	1.74	0.9-3	3
10	0.1-1	0.10	0.67	0.3-0.9	2
10	<0.1	0.03	0.26	<0.3	1

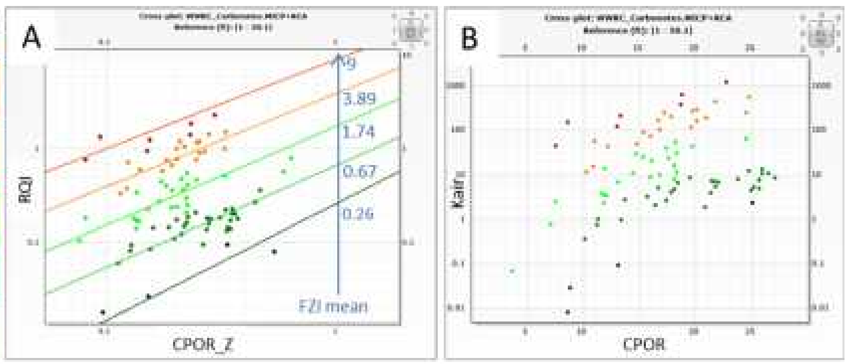

Figure 2: A/ Cross plot of RQI-CPORz color-coded by the five FZI reservoir rock types. Each regression line is a porosity-permeability transform and corresponds to a unique RRT. The intercept of the unit slope line with CPORz=1 corresponds to a FZI mean unique parameter for a RRT. B/ Cross plot of permeability (Kair) versus porosity (CPOR) color-coded by FZI reservoir rock types.

INTEGRATED RESULTS: RESERVOIR ROCK TYPES, RCA AND MICP TESTS

1. FZI reservoir rock types and capillary pressure curves from MICP

Mercury Injection Capillary Pressure tests, MICP, provide a measure of the total connected pore volume together with an appreciation of the size of the connection within the sample. Thus, the shape of the plotted capillary pressure or the pore throat size distribution is considered a diagnostic of the formation's fluid storage and flow properties.

The plots in figure 3 shows A/ 50 capillary pressures and B/ pore throat radius distribution color coded by the five FZI reservoir rock types. Overall, by the increase in the values of FZI and therefore the quality of the reservoir rock type:

✓ The shape of the transitional zones of the capillary pressure curves becomes sharper and the amount of initial water saturation decreases.

- ✓ The entry pressure for non-corrected Pc curves decreases. Consequently, pore throat size increases in average with the higher quality reservoir rock types.

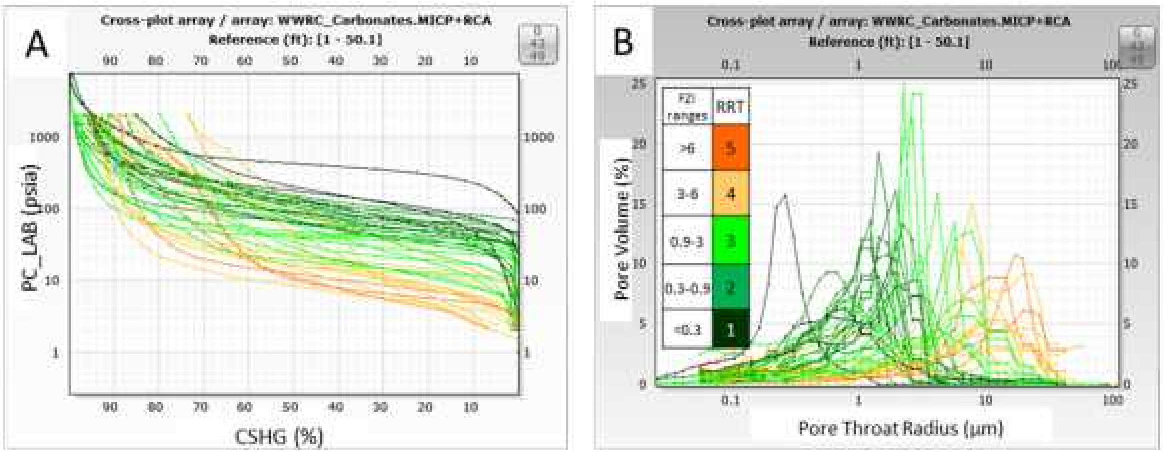

Figure 3: A/ Capillary pressure tests (MICP) and B/ pore thorat size distribution from MICP color-coded by the five FZI RRT.

2. FZI reservoir rock types and Archie's paramaters *m*

Archie exponent *m* [4] represents how the relationship between porosity and conductivity varies from a directly proportional relationship. Exponent *m* reflects the amount of tortuosity inherent in a pore system, resulting from an assemblage of equally sized grains. From the fifty carbonate rock samples Archie *m* exponent varies from 1.8 to 2.5.
Figure 4 shows cross plots of *m* and core porosity, color-coded by the five FZI reservoir rock types, for the limestone and dolostone data sets.

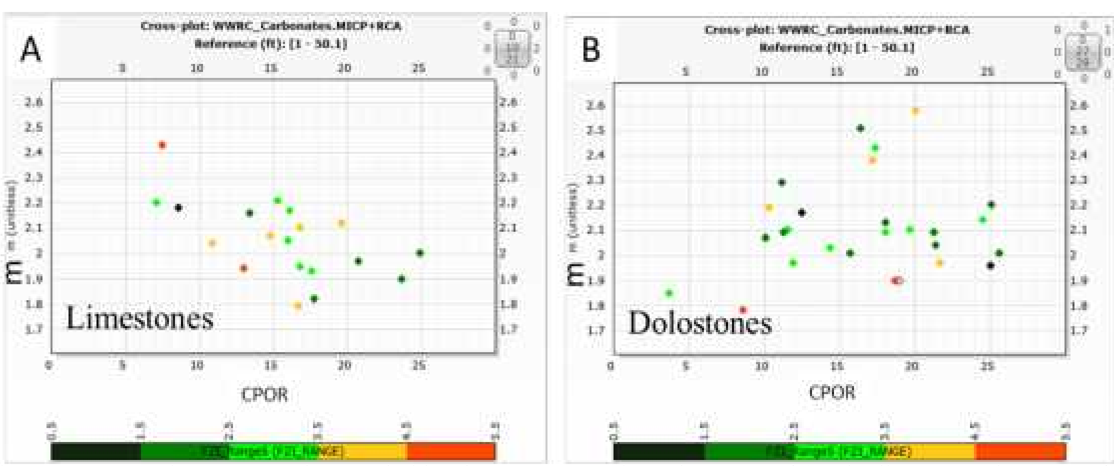

Figure 4: Cross plot *m*-FZI colour coded by the FZI reservoir rock types. A/ for the limestone data set, B/ for the dolostone data set.

For limestones, *m* is decreasing with the porosity while for dolostones it tends to increase. This is explained by the pore texture that characterizes the two types of carbonates in the highest and lowest porosities. Indeed, in this data set, good quality dolostones come from massive recrystallisation of limestones and present mainly an intercrystalline porosity with connected vugs. Thus, volume and size of pores reflect dolomite crystal size and arrangement. Increasing volume of intercrystalline pores and vugs, increases the tortuosity of current paths and therefore *m*. On the other hand, high quality limestones often present interparticle and unimodal porosity (case of the oolitic formations). The tortuosity of the current path and consequently *m* are small. Low quality limestones mix interparticule, connected moldic and vuggy porosity and present reduction of the area available to the flow, a high degree of tortuosity and therefore a higher *m*.

3. Rock Type Characterization

For the limestones, reservoir rock type quality is obviously controlled by the type of porosity or pore texture and the modality-size of the pore throat radius. For each rock type an ID card is generated (see figure 5). Low quality rock types (RRT1-2) present non-connected moldic and intraparticle porosity with a bi-modal pore throat radius system. Diagenetic micritization of the shells is only seen in the RRT1 and RRT2 and is responsible of the insulation of the molds when bioclasts are leached. Archie's component *m* and *SWir* (>25%) are high for these samples. Higher quality rock types (RRT 3-4) show intercrystalline, interparticle and well-connected porosity with uni- to bi-modal pore throat radius. Best RRT 5 limestones are poorly cemented, well sorted and present well connected macroporisity, either interparticle or vuggy. For dolostones, many samples correspond to a massive recrystallisation of the calcite, erasing the original texture of the rock. RRT quality depends on crystal size and the presence of vugs.

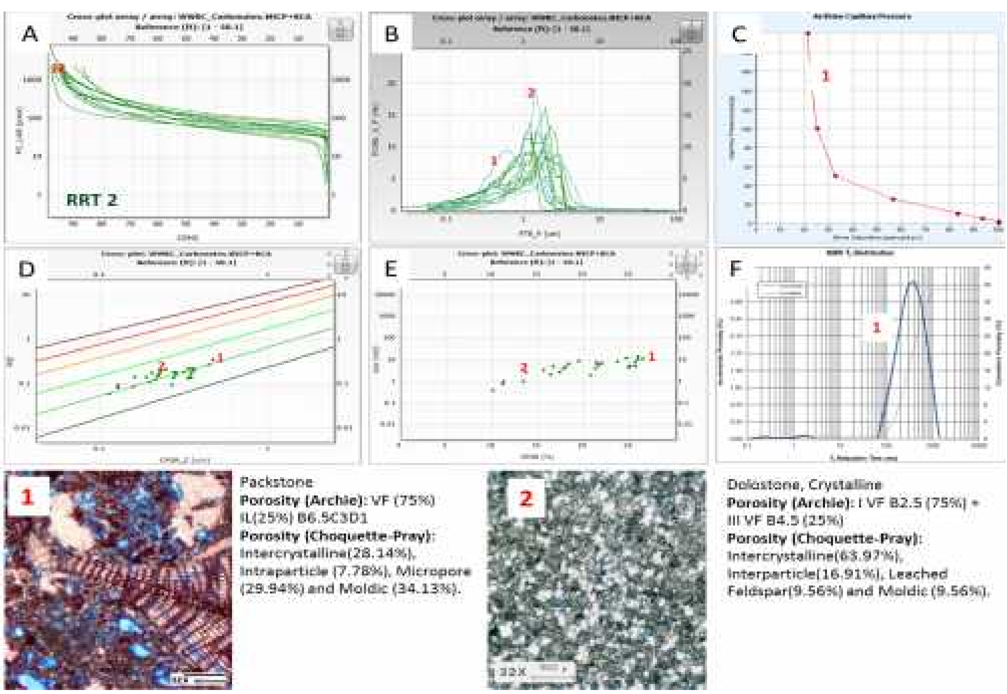

Figure 5: Reservoir rock type RRT2 ID card with A/ Mercury Injection Capillary pressures B/pore throat radius, C/ Air-brine Capillary pressures. D/ CPOR-RQI cross plot, E/ CPOR-Kair cross plot. 1, 2 are two

samples of carbonate with texture and porosity classifications defined on thin sections. F/T2 distribution echo-spacing 0.2.ms, 100% brine saturation.

The five reservoir rock types define a unique permeability/porosity equation that can be propagated to the full core dataset and the Log domain if available (see table 1 below).

Table 1: Rock Type Characterization

Rock types	1	2	3	4	5
CPOR	Mean: 16% Range: 8-27%	Mean: 21% Range: 10-30%	Mean: 17% Range: 05-38%	Mean: 18% Range: 11-25%	Mean: 15% Range: 7-23%
Kair	Mean: 2mD Range: 0.1-8mD	Mean: 7mD Range: 0.5-40mD	Mean: 30mD Range: 0.5-250mD	Mean: 170mD Range: 10-550mD	Mean: 380mD Range: 50-1200mD
Duhnam Classification	60%P, 10% G, 30% CD	40% CD, 30% G, 30% P	50% CD, 40% G, 10% P	50% G, 20% P, 30% CD	70% G, 10% P, 20% CD
Type of porosity	70% InterC 10% InterP 20% IntraP	70% InterC 20% InterP 10% IntraP	40% InterC 40% InterP 20% IntraP	30% InterC 60% InterP 10% IntraP	20% InterC 70% InterP 10% IntraP
Cementation Exponent (m)	Mean: 2.14 Range: 1.96-2.18	Mean: 2.01 Range: 1.9-2.51	Mean: 2.1 Range: 1.85-2.43	Mean: 2.13 Range: 1.79-2.6	Mean: 2.03 Range: 1.9-2.40
Saturation Exponent (n)	Mean: 1.85 Range: 1.89-2.8	Mean: 1.67 Range: 1.13-2	Mean: 1.76 Range: 1.6-2.36	Mean: 1.92 Range: 1.6-2.47	Mean: 1.96 Range: 1.6-2.28
SWir	Mean: 35% Range: 30-45%	Mean: 17% Range: 10-26%	Mean: 20% Range: 5-40%	Mean: 15% Range: 5-30%	Mean: 13% Range: 6-25%
RQI/CPOR regression	log10(RQI)= + 1.2550 * log10(CPOR_Z) - 0.58479	log10(RQI)= + 1.0956 * log10 (CPOR_Z) - 0.17573	log10(RQI)= + 1.0623 * log10 (CPOR_Z) + 0.24060	log10(RQI)= + 1.0006 * log10 (CPOR_Z) + 0.5905	log10(RQI)= + 0.9661 * log10 (CPOR_Z) + 0.95270

P: Packstone, G: Grainstone, InterC: Intercrystalline, InterP: Interparticle, IntraP: Intraparticle, CD: Crystalline Dolostone

CONCLUSIONS

Results of this study demonstrate a successful new method using unsupervised neural networks to determine the optimal number of reservoir rock types for hydraulic unity analysis of carbonate reservoirs. The resulting rock type characterization provides a quantitative means of representing RQI/CPOR for further application in log analysis.

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