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# Feature Rock Typing, the New Approach in Heterogeneous Carbonate Reservoirs

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## Abstract

Nowadays rock typing is a major tool for identifying lateral and vertical facies changes in reservoir properties. The Upper Dariyan Formation is one of the most important carbonate reservoirs in northern plunge of Qatar arc which was deposited on a broad carbonate shelf. This reservoir is located out of water for a period of time, so solution is the main digenetic process that increases the reservoir quality in upper parts and gradually its effect decreases towards down. In the studied reservoir, diagenesis controls the behaviour of reservoir, so in nearby distances permeability varies between 0.1 and 1000 Md. With finding diagenesis effective depth, reservoir is classified into 3 coarse areas: digenetic, transition and non-digenetic ones. In this article we tried to use all data in different methods such as FZI, FZIT, PC, and ANN[1] and Hydraulic unit to determine rock typing in digenetic area. The results show that empirical equations are not applicable in these sorts of reservoirs because in specified intervals, the outputs of mentioned methods were different. In digenetic area by using of Spectrometry on CT scan data, dense, porous, vuggy and cave areas are identified and their results are classified and controlled with SEM, T2 and pore size distribution of lab test and Permeability. This method is one of the direct ways for dividing rock types with calculation of coloured surface, trapped oil volume in caves and areas with effective and non-effective permeability which is obviously separable. By calculating area vertically in any CT scan, a cross plot between porous area and permeability shows a positive Correlation Coefficient (R2=0.87) and this relationship for other areas was negative. In non-digenetic area with low heterogeneity, rock typing is done with FZI. The model reveals that Upper Dariyan is subdivided into three coarse and 10 fine rock types, which are controlled with basement faults behaviour and they limit diagenetic process. The core calibrated feature rock typing model was applied to noncore sections in vertical and horizontal drilled wells in Upper Dariyan formation and logging while drilling (LWD) improves rock typing and permeability estimation, thus valuable input data for static modelling should be provided.

## Introduction

The South Pars/North Dome gas and oil fields are located on old broad Precambrian structural highs, designated Fars/Qatar Arch. The Upper Dariyan Formation[2] is one of the most important carbonate reservoirs in IRAN which the hydrocarbon accumulation was not well known in northern plunge of Qatar arc. This layer is mainly composed of porous limestone, bioturbated skeletal wackestone to packstone fossilliferous, including some layer of Rudstone, grainstone, with good porosity and generally oil stained. Towards the base, the limestone becoming fine-grained fossilliferous contains algae and foraminifera. Top of the Dariyan Formation is an erosional surface and is unconformable with the overlying Kazhdumi shale. This layer has an average thickness of is 58 m and it is consisted of four major zones which can easily be distinguished according to lithology and results of the Petrophysical evaluation. Zone-1: Limestone, porosity ranges 15 to 37% (27% in average), Zone-2: Limestone, porosity ranges 18 to 35% (27% in average), Zone-3: Limestone, porosity ranges 12.5 to 30% (28% in average) and Zone-4: Limestone, porosity ranges 2 to 28% (15% in average). According to drilled wells and core description study (3), general reservoir characterizations in top 20 meters of reservoir which cause high heterogeneity are as follow: A)From top to -1075 mss a high reservoir

[1] Artificial Neural Network
[2] Shuaiba Equivalent

quality is related to the effect of digenesis which decreases towards down and it completely removes in -1066 mss B) Core-derived permeability measurements in vertical section are in the range of 15-141 md, C) Secondary porosity (Vagular and Cave), D) Heterogeneity is distributed in lateral section based on structural elevation so that Lateral Facies changes and permeability variation with so many fractures are propagated. In neighbourhood fields like Al-Shaheen, presence of 1000mD permeability besides 1mD is reported which is one of the reasons for high heterogeneity. In these types of reservoirs which have high permeability variations, with different pore throat size, initially conventional rock typing methods such as PC, FZI/FZIT and ANN (based on all logs and CCAL data) are used, results show that in the same interval the responses are different, it seems that using mathematical equations for rock typing in reservoirs that have high heterogeneity, is not a suitable method, so feature rock typing is used for this reason. For rock typing, Petrophysical logs and X ray CT imaging are evaluated from geological aspect and the results are as follow:

- Little variations in PHIE besides Permeability and water saturation especially in the first three zones shows negligible effect of porosity in rock typing.
- SGR and CGR logs separation in lower parts of Kazhdumi formation in petrophysical evaluations, it doesn't show dolomite and it can be the reason for existence of uranium waters which are inserted in Upper Dariyan formation while raining and it causes leaching and vugs, this issue is not obvious in some wells which is located in the flank of reservoir. It is necessary to mention that Lithocodum Bussinella fossils which are abundant in crestal area of reservoir and have a dimension of about 4 cm, created big cave in reservoir after solving.
- The porosity is calculated by two different methods, using sonic log and using RHOB and NPHI together. Calculation of porosity with each method shows a separation in a track. This separation in upper parts of reservoir is more due to the diagenitic effect and towards down with decreasing of digenetic effect, becomes less gradually.
- Existence of bimodality in NMR logs such as T2 distribution in top 20 meters of reservoir which is capable for correlation with Al-shaheen is another evidence for reservoir heterogeneity.
- X ray CT imaging of the core relieved a vuggy porosity and the thin-section image provides information on the macro and micro porosity of the rock matrix. These two imaging techniques helped to determine pore size and shape distribution, so pore structures are related to permeability in carbonate rock samples.

## NMR Experiences

However there are wide ranges of permeability calculation methods but most of them aren’t able to find relevant relation in carbonate rocks due to presence of varied pore types.  Carbonate formations in general, have broad pore size distributions, from microcrystalline to large vugs. Nuclear magnetic resonance (NMR) technology has broad range of usage in exploration and production fields. Beside the special core analysis data, NMR measurement can recognize the pore characteristics by measuring the relaxation time which is related to pore space/geometry and fluid properties. In this study we have a set of NMR data which is used in permeability estimation within Dariyan Formation. On the basis of available core samples upper part of Dariyan formation possess the variety of pore types including inter crystalline, inter particle, fracture and especially vuggy porosity. Lucia (1983) (1) showed that the most useful division of pore types for petrophysical purpose was pore space between grains or crystals, called inter particle porosity and all other pore space, called vuggy porosity. The vuggy pore space was further subdivided by Lucia (1983) (1) into two groups depending on how the vugs are interconnected: Vugs interconnected only through the interparticle pore network are separate vugs, and vugs that form an interconnected pore system are touching vugs. The work by Lucia is the concept that pore-size distribution controls permeability and saturation and that pore-size distribution is related to rock fabric. Due to presence of these pores it is important to recognize appropriate T2 cutoff for estimation of bound volume index (BVI). The BVI is converted to permeability through the several methods like FZI/FZIT (2). The original method of computing permeability from NMR well logs by using a constant T2 cutoff didn’t produce satisfactory results in this system. It seems that it is due to several varied pore system with varying degrees of vuggy porosity. A more accurate method of computing permeability would take into account by the variations in pore structure which occur throughout the formation. Subsequently variable T2 cutoffs are used to predict the accurate bound fluid volume (BFV). BVF should be utilized in permeability prediction regarding to below equation.

$$Permeability = c*(\frac{FFV}{BFV})^a \times \left(\frac{PHI}{10}\right)^b$$

Where the parameters a, b, and c are determined from the best fit to the core permeability measurements. Based on these samples, the optimal values are: a = 2, b = 4 and c = 0.1 in Coates equation. Based on available core data a specific T2 cutoff dedicated to each zone. The NMR well log is divided among these groups and the BVI is then computed as the porosity with associated T2 values less than the T2 cutoff for that group. Once the BVI is known, we compute the permeability for that depth through the Coates equation. There is an idea that large pores do not contribute much to the formation permeability, and it is not important if the NMR experience distinguishes them from smaller pores. In consideration of this issue, it is recommended not using T2 larger than 750 ms when computing permeability in carbonates. Figure 1 illustrates two different types of samples that include large pore (Vuggy) and small pore. However there is a considerable difference in pore size distribution in large pore and normal pore scale within core data but it cannot be clearly distinguished in the NMR relaxation time. Thus it is not possible to use NMR experience to identify different rock types of Upper Dariyan Formation which produce more heterogeneity in upper parts.

## Methodology

The methods which are used for rock typing are as follow:

## Rock Typing by RQI/FZI and FZIT Methods

The flow zone index method is an approach for classifying rock types and prediction of flow properties. This method is based on sensible geological parameters and physics of flow at pore scale that are provided based on the calculation of flow zone index and rock quality index values. The main idea is to group data according to their flow zone index values. The method is based on modified Kozney-Carmen equation and the concept of mean hydraulic radius. It is an effective technique for rock type classification and excellent permeability-porosity relationships can be obtained once the conventional core data are grouped according to rock types. The derivation of FZI and FZIT equations are based on the assumption that porous medium can be represented by a bundle of capillary tubes FZIT method is based on FZI equation and it uses permeability which is taken from NMR. The RQI values are calculated for the available core data from different wells. Sorting data based on FZI, helps arranging K-Phi data in a way that shows a good correlation. Figure shows RQI vs. normalized porosity for all core sample data available. As it is clear, no distinct border is recognizable between these data points to distinguish between different classes of FZI and FZIT values. Base on RQI/FZI and FZIT method, six different rock types are defined. According to the little changes in porosity values in the first three zones of reservoir, FZI and FZIT method don't give a good resolution of rock typing in the heterogeneous areas.

## Rock Typing by Pc and J function Methods

As the J function method cannot discrete the different rock types clearly in heterogeneous area of this reservoir, the assumption of constant Tortuosity for all plugs is used and the calculation of J* modification have been applied according to the Tortuosity values. The values of Swi and J* could be plotted against water saturation for each sample. According the range of $k*\Phi$, seven rock types identified for U.Dariyan reservoir. The results of PC method which are related to laboratory results determined one rock typing for permeability which is more than 40md, so this is the main challenge in permeability which is more than 40 md and it can't be divided by mentioned method so this method is not acceptable here.

## Rock Typing by ANN Method

By using of neural Network method the classification was carried out on petrophysical raw data. The 10 classifications were defined. To follow the procedure, by considering the reservoir rock quality based on core results, finally 10 classifications were merged to four classifications only for upper part of Upper Dariyan. In continue conventional mathematical relations which are based on CCAL, SCAL and petrophysical raw data are mentioned and they show that in top 20 meters of reservoir number of rock typing for identifying heterogeneity were not suitable, and for a specific depth, each method shows an individual rock typing, results are shown in Figure 2.

## Feature Rock Typing Methodology

Our approach includes CT data to characterize the carbonate pore space, with size varying by spectrometry which is based on RGB model, defined pore spaces beside Core and thin section, SEM, Permeability and NMR show different types of rock typing (4). The main purpose of the RGB colour model is for sensing, representation and display of images in electronic system. RGB (red, green and blue) refers to a system for representing the colours to be used on a computer display. Red, green and blue can be combined in various proportions to obtain any colour in the visible spectrum. Levels of R, G and B can each range from 1 to 100 percent of full intensity. Initially, Spectrometry model was run and QC in Kazhdumi shale and then the model was applied on all raw CT scan data. CT scan data shows four areas which are shown separately in red, blue and black. Green, red and blue colours show pore size which increasing from Green, red to blue respectively, but black colour shows vugs and caves (>2cm) which were not read by T2 distribution Figure 3. In continue, area for each Colored sample was calculated and plotted versus permeability. This cross plots shows blue colour which is represented of big pore size has a positive relation with permeability (R2=0.87) and green and red colours have negative relation with permeability (R2=0.66.and 0.63.respectively) Figure 4. Three colored curves, permeability and T2 log mean curve are classified based on unsupervised neural network method and in 20 meters of reservoir which has a high heterogeneity. 5 different rock types are determined and the results which are combined with pore throat size, thin section description and permeability are shown in Table 1.

## Conclusions

Upper Dariyan Formation is an oil producer reservoir which consists of heterogeneous carbonate. Based on available core and log data it has several heterogeneities from lithology, porosity and throat size to stress regime which cause many difficulties during the reservoir study especially in fist fifteen meters. We have focused on several ways to characterize the upper part which is the most important one due to having maximum storage and flow capacity. Some methods have examined to find a meaningful rock typing such as FZI, PC, NMR, and ANN method. All mentioned methods have not been able to detect heterogeneity basis in upper parts because they mainly focus on porosity instead of pore throat setting and their reaction. Therefore it was decided to utilize CT scan data to find a new approach nominated as feature rock typing. It can identify different pore types and rock bodies by using coloured base method and RGB concepts. In order to find heterogeneity we assign a colour code to each range of brightness which was equal to a specific property by trial and error examination during calibration with or observation CT sample. We extract three curves which are representative of different characters of our sample and they show a considerable relation with reservoir permeability. These curves beside the permeability, thin section and SEM data have been used to find desired rock types in upper part and divided it to Five Rock Type with unique definitions which was not possible to be detected by other methods.

## References

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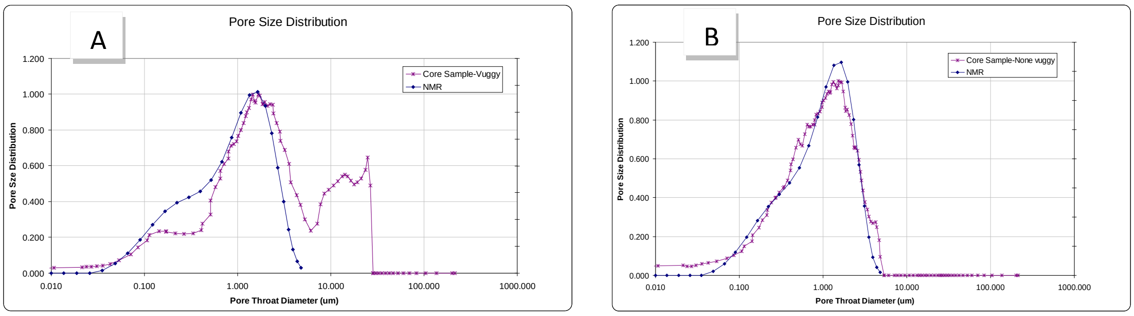



Figure 1: A)Comparison of Pore size distribution versus NMR T2 distribution in vuggy sample
B) Comparison of Pore size distribution versus NMR T2 distribution in none vuggy sample

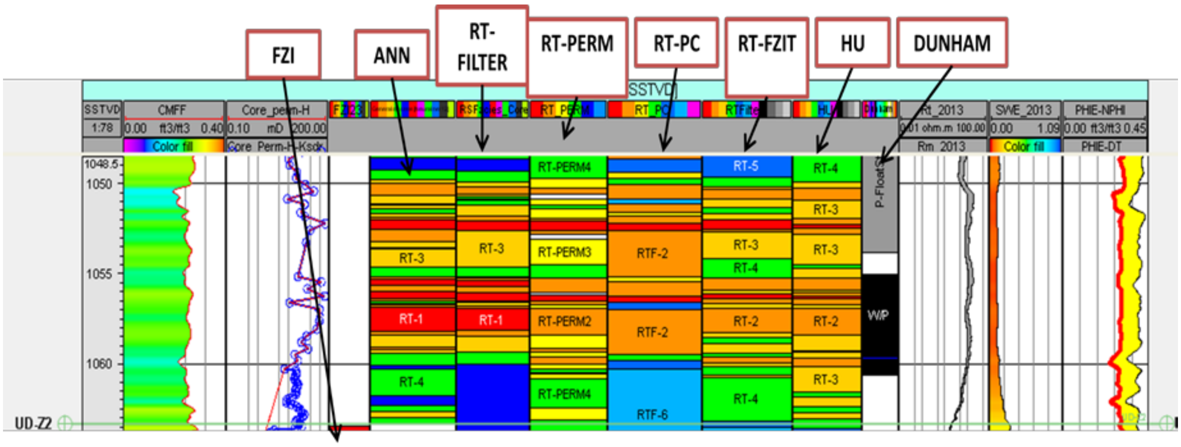



Figure 2: Comparison Between all of Rock type which be generated by Different Method

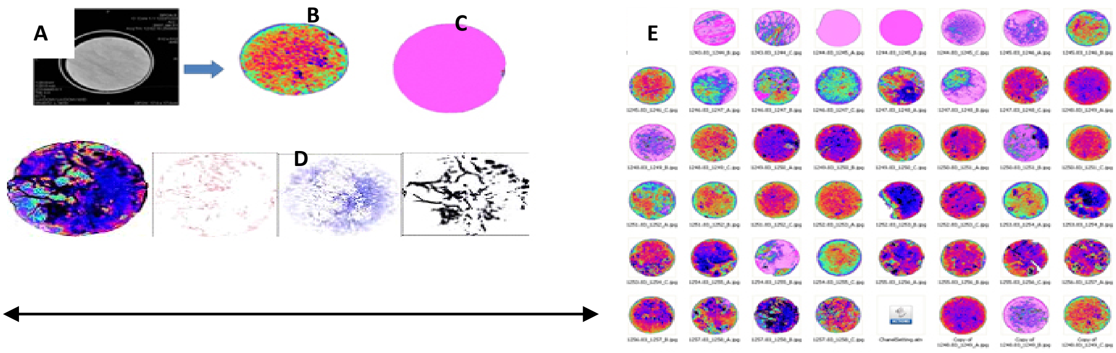



Figure 3: A) Raw CT scan Data B) After Applying RGB model C) QC with Kazhdumi shales D) Extracting Red, Blue and Black area from CT scan Data and calculating the area E) All of CT Samples

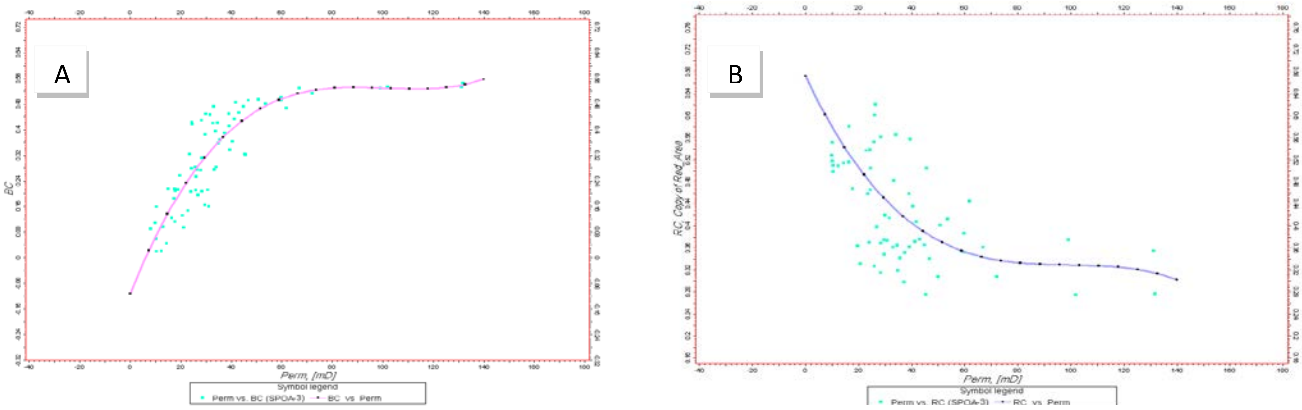
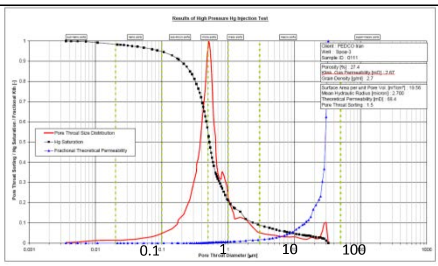
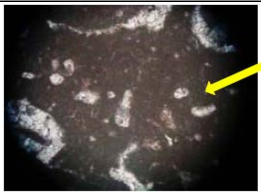
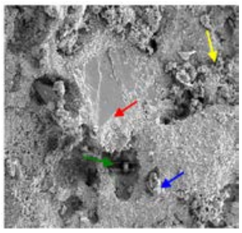
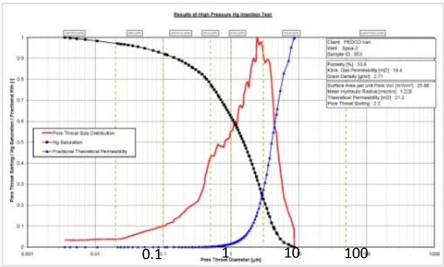
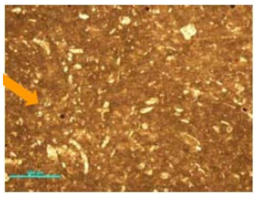
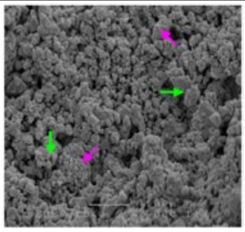
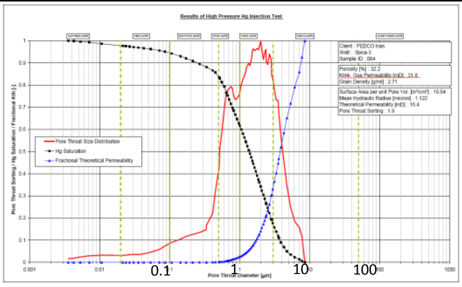
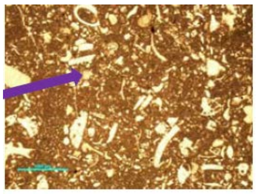
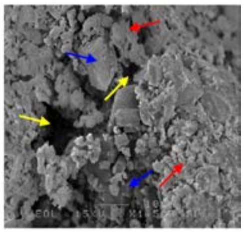
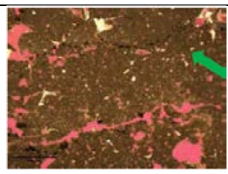
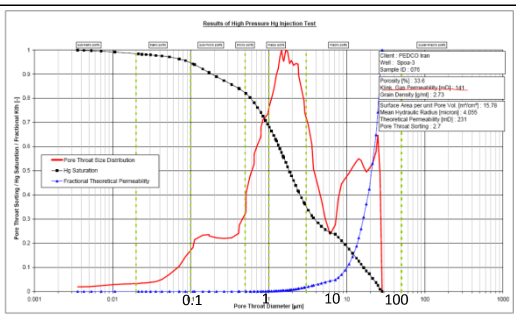
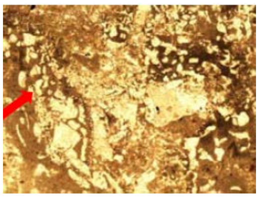
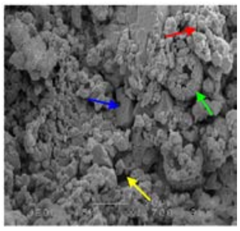



Figure 4: A) Blue color which is represented of big pore size has a positive relation with permeability
B) Red colour has negative relation with permeability

Table 1: Rock Type Classification

| Perm Range | Rock Type Code | Pore Throat Size | Thin section Results | SEM Characterization |
|---|---|---|---|---|
| ***< 15*** | ***5*** |  Pore Throat Diameter (μm) |  ***Mudstone to Wackestone (Slightly Argillaceous Limestone)*** |  A) |
| ***15>Perm>25*** | ***4*** |  Pore Throat Diameter (μm) |  ***Bioclastic wackestone to mudstone*** |  B) |
| ***25>Perm>40*** | ***3*** |  Pore Throat Diameter (μm) |  ***Porous bioclastic wackestone*** |  C) |
| ***40>Perm>70*** | ***2*** | ***N.A*** |  ***Porous wackestone to packstone having vuggy porosity*** | ***N.A*** |
| ***70>Perm>141*** | ***1*** |  Pore Throat Diameter (μm) |  ***Porous bioclastic packstone to grainstone having vuggy porosity*** |  D) |

A) 77µm Pores and larger crystal distribution within the matrix,(1) note the micritisation of the larger crystal (red arrow), the vuggy porosity (green arrow), the intercrystalline porosity (yellow arrow), and microspar that partially fill up vuggy pores (blue arrow). B) 9µm Rounded micrite shows serrate contacts between crystals (pink arrow) and subhedral to anhedral microspar shows point contacts (green arrows) C) 11µm Rounded micrite (red arrow) and euhedral to subhedral microspar (blue arrow); note intercrystalline micro porosity (yellow arrow). D) 11µm (C) Subhedral to rounded micrite (red arrow) and subhedral to anhedral microspar (green arrow); spherical structu res could represent pellets (green arrow). Note the intercrystalline micro-porosity (yellow arrow)