

# Porosity and Permeability Analysis from Well Logs and Core in Fracture, Vugy and Intercrystalline Carbonate Reservoirs

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## Abstract

The 60% of the world's oil and 40% of the world's gas reserves occurs in carbonate reservoirs. Around 70% of oil and 90% of gas reserves held within the carbonate reservoirs in the Middle East for example. Carbonates can exhibit highly varying properties (e.g., porosity, permeability, flow mechanisms) within small sections of the reservoir, making them difficult to characterize. A focused approach is needed to better understand the heterogeneous nature of the rock containing the fluids and the flow properties within the porous and often fractured formations. This involves detailed understanding of the fluids saturation, pore-size distribution, permeability, rock texture, reservoir rock type, and natural fracture systems at different scales. Deposition, sedimentation, diagenesis and other geological features of carbonate rocks has been studied leading their classification into: mudstone, wackestone, packstone, grainstone, boundstone and crystalline carbonate rocks. Various features such as fractures and vugs, which influence its petrophysical behavior, characterize all these. The study of the main features of carbonate reservoir using Archie's cementation exponent "m" is an acceptable method of verifying the geological features in the reservoir, which actually contribute to rock fluid properties and other production attributes of the reservoir. This proved for some reservoir using well log values for KF2 oil field in Iraq. The dominating geological features of the field confirmed from a graphical representation of the different data from field reservoir. The reservoirs used as case studies in the research classified into different carbonate rocks using a graphical plot of their permeability against porosity values. This result gives an evidence of the textural and grain size characteristics as well as the effective pore sizes of the reservoir. This method of analysis makes it easier to evaluate the post diagenetic strength of the reservoir rocks and fluid hosting capability in assessment of recovering.

**Keywords:** Carbonate reservoir; Petrophysical; Diagenesis; Fractures; Vugs; Porosity and permeability

## Introduction

Reservoir is a body of rock that has pores to contain oil and gas, and sufficient permeability to allow fluid migration. In order to have a hydrocarbon-producing reservoir, the following conditions must exist:

1. There must be a body of rock having sufficient porosity ( $\Phi$ ) to contain the reservoir fluids and permeability ( $k$ ) to permit their movement.
2. The rocks must contain hydrocarbons in commercial quantities.
3. There must be some natural driving force within the reservoir, usually gas or water, to allow the fluids to move to the surface.

Porosity is the ratio of the pore volume to the bulk volume of the reservoir rock on percentage basis. That is

$$\text{Porosity} = \frac{\text{bulk volume}}{\text{pore volume}} \times 100\%$$

Bulk volume = the total volume of the rock

Pore volume = the volume of the pores between the grains

The measurement of porosity is important to the petroleum engineer since the porosity determines the storage capacity of the reservoir for oil and gas. It is necessary to distinguish between the absolute porosity of a porous medium and its effective porosity. In porous rocks there will always be a number of blind or unconnected pores. Absolute porosity includes these pores as well as those open to the flow of fluids whereas the effective porosity measures only that part of the pore space that is available to fluid flow. There are several ways to measure the porosity:

1. Laboratory measurement of porosity

Bulk volume is first determined by displacement of liquid, or by accurately measuring a shaped sample and computing its volume. Then any of the following methods are used to measure either the pore volume or grain volume. Summation of Pore Fluids involves independent determination of gas, oil and pore water volumes from a fresh core sample (Figure 1).

The pore volume is determined by adding up the three independent volumes. Washburn-Bunting method measures pore volume by vacuum extraction and collection of the gas (usually air) contained in the pores. Liquid Re saturation pores of a prepared sample are filled with a liquid of known density and the weight increase of the sample is divided by the liquid density. Boyle's Law Method involves the compression of a gas into the pores or the expansion of gas from the pores of a prepared sample. Either pore volume or grain volume may be determined depending upon the porosimeter and procedure used. Grain Density measures total porosity. After the dry weight and bulk volume of the sample are determined, the sample is reduced to grain size and the grain volume is determined and subtracted from the bulk volume.

2. Petrographic analysis of thin sections of a rock sample. This is

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**Received** June 18, 2015; **Accepted** June 30, 2015; **Published** July 25, 2015

**Citation:** Sadeq QM, Wan Yusoff WIB (2015) Porosity and Permeability Analysis from Well Logs and Core in Fracture, Vugy and Intercrystalline Carbonate Reservoirs. J Aquac Res Development 6: 371. doi:10.4172/2155-9546.1000371

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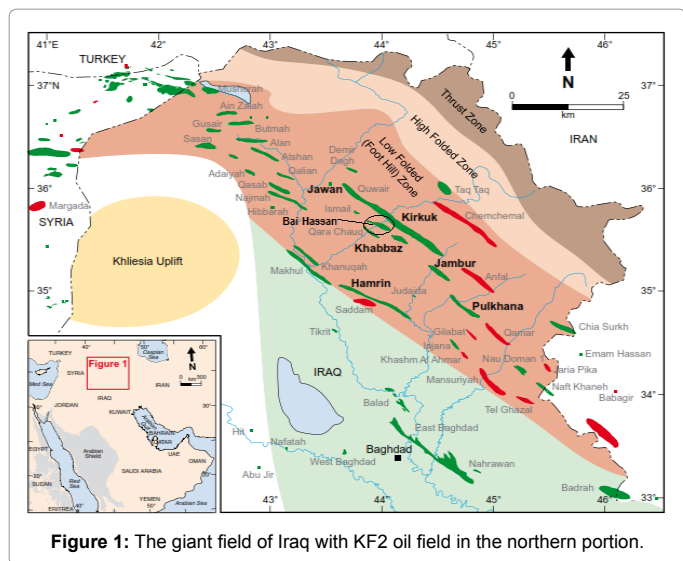


Figure 1: The giant field of Iraq with KF2 oil field in the northern portion.

done by point counting of pores under a microscope. Impregnation of the sample in a vacuum with dyed resin facilitates pore identification.

3. A common source of porosity data are the well logs. Porosity may be calculated from the sonic, density, and neutron logs. These three logs are usually referred to as porosity logs.

4. Porosity may also be obtained from the resistivity logs.

Carbonate porosity includes three end-member genetic categories; purely depositional pores, purely diagenetic pores, and purely fracture pores. Intermediate types exist, of course, but the point is that there are three main types of carbonate porosity that represent distinctly different geological processes. Carbonates, porosities and permeabilities are dependent on the nature of the rock developed during deposition and the diagenetic/solution processes.

Main properties of reservoir study are porosity and permeability. Porosity is the ratio of voids in a rock to the total volume of rock and reflects the fluid storage capacity of a rock thereby making it a reservoir. The porosity or percentage pore volume of reservoir rocks can be measured from well cuttings, core samples from drilling or wireline well logs. Typical generally admissible porosity values for an oil reservoir range from between 10% and 25%, with porosity values of above 25% desirable [1]. Permeability on the other hand explains how connected reservoir pores, vugs or fractures are structured and variably determines the ease of flow of fluids through the rocks. They are measured in darcy or millidarcy. Permeability and porosity of a rock are interrelated as higher porosity implies higher permeability. In addition, the grain size of a rock also determines the pore throat (narrow connections) that can exist in the reservoir rock thereby controlling the permeability rate. Coarse grained rocks such as carbonates and sandstones have bigger pore throats, thus they are highly permeable while rocks with lesser grain size as shale have smaller pore throats with little or no permeability [2]. The degree of permeability depends on the size and shape of pores, the size and shape of their interconnections, and the extent of interconnections Figure 2. The relationship between porosity and permeability for a given formation is not necessarily a close or direct one. However, high porosity is often associated with high permeability. Many investigators have attempted to correlate permeability to porosity, grain size and shape, and packing. The most frequently used relation was developed by Kozeny as follows:

$$K = \frac{\Phi^3}{5 \times S_v \times (1 - \Phi)^2}$$

k=permeability, cm<sup>2</sup> (=1.013 × 10<sup>8</sup> darcies)

Φ=effective porosity

S<sub>v</sub>=total grain surface/unit volume of reservoir, cm<sup>2</sup>/cm<sup>3</sup>

## Geological Setting

KF2 Field is one of several elongated, asymmetrical, doubly plunging anticlines that characterize the Foothills region of the Unstable Shelf Zone in eastern Iraq. The northwest-southeast trending structure measures 34 km long and 3.8 km wide. Two individual domes separated by a shallow saddle make up the KF2 structure. Kithke Dome is the larger and more prolific of the two domes. It has a significant surface expression. Daoud Dome does not have a surface expression, is smaller, and less prolific [3]. The Shahl Saddle physically separates the two domes. KF2 field occupies a stratigraphically complex area comprising multiple facies developments of a complicated diagenetic history. Abundant and variable porosity and permeability exist which, although primarily lithology dependent, are enormously enhanced by the development of intensive faults, fractures and joints, this combination of uncommonly high porosity and permeability gives rise to enormously high and continuous production. The maximum reservoir thickness generally taken as approximately 225 m comprising five main facies types:

### Tidal dolostone facies

It is characterized by the occurrence of stromatolitic dolostone microfacies, which occur as thin layers punctuating the lagoonal facies and developed as marginal tidal-flat complexes of the lagoonal environment. Relics of fenestral fabric are characteristic but commonly obliterated by intensive dolomitization.

### Lagoonal facies

This facies is commonly found in the western part of Kirkuk area and characterized by dolomitic limestone and dolostone of peloidal-

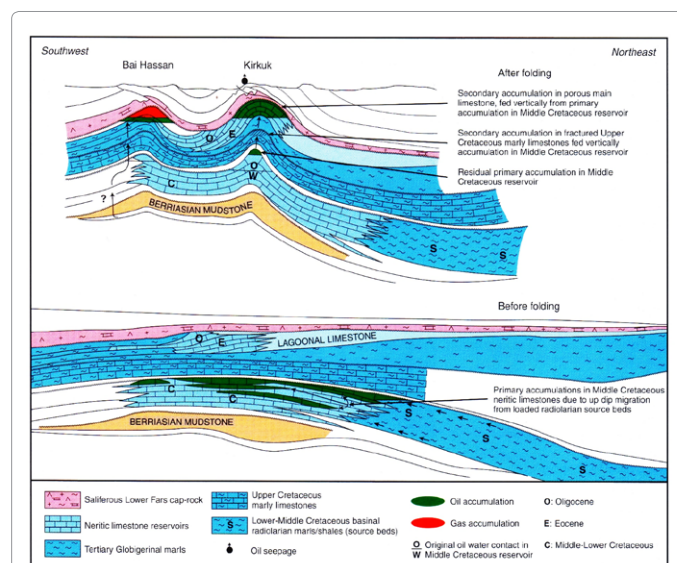


Figure 2: Anticline formation of KF2 oil field because of folding (modified from Gong and Gerken, 2003).

miliolid packstone to grainstone. Other grains include fragments of algae and mollusks. Early cementation of this facies reduces dolomitization effects; however, selective dolomitization is frequently recognized and lagoonal dolomudstone can be found alternating with the limestone.

**Orbitolina-bearing facies**

This is a dark grey orbitolina-rich limestone, which is variably dolomitized. Grains are dominated by large benthic orbitolinids. Microfacies range from whole-foram grainstone to wackestone to fragmented packstone to wackestone. Other subsidiary grains include bioclasts of algae, rudists and mollusks.

**Rudist bioclastic facies**

It is characterized by high-energy bioclastic packstones. The majority of grains are rudist fragments intermixed with fragments of open-shelf faunas. It is highly bioturbated and interlayered with thin shaley seams.

**Basinal foraminiferal argillaceous facies**

This is the most eastern facies of the area. It is characterized by planktonic foraminifera intermixed sporadically with calcispheres forming bioclastic packstone to wackestone microfacies. Intermixture with open-shelf bioclasts is common. The matrix is argillaceous micrite and marl.

Most of the oil in the Kirkuk and KF2fields is contained in fabric selective porosity; non-fabric selective porosity or macrovoids comprising fissures, large vugs, fractures and caverns account for only minor amounts. Permeability and production, however, are almost entirely along these channels, a fact that been indicated quite early in the history of the field.

**Methodology**

The method of study based on well log (Petrophysical) data from KF2oil field in Northern Iraq. Porosity, permeability, formation resistivity and connate water resistivity values for different wells were obtained from well logging of the oil field (A1 to A2, A3, A4 and A5).

Advanced core data analyses for KF2 cores were abundant enough that a study of porosity versus the Archie cementation exponent m was conducted [4]. The data and results are plotted in Figure 3 and Table 1. Archie “m” as a function of porosity is given as:

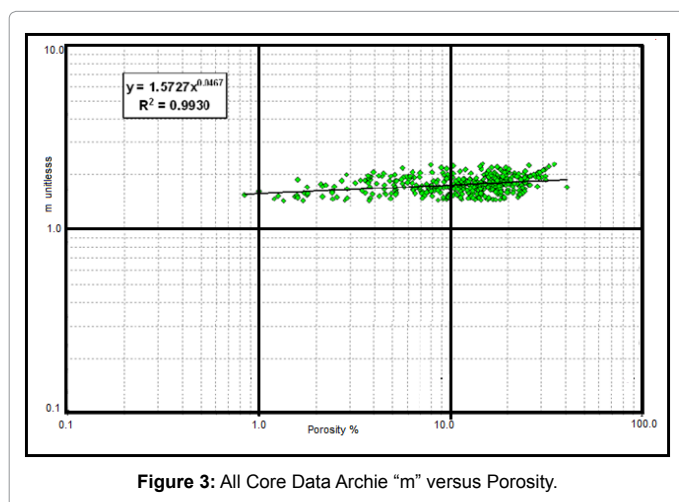


Figure 3: All Core Data Archie “m” versus Porosity.

	Porosity (%)	Formation Factor (F)	Computed (m)
Mean	16.2	197.9	1.88
Median	18.5	31.4	1.91
Std. Deviation	9.6	445.3	0.22
Minimum	1.0	9.0	1.44
Maximum	37.5	2273.9	2.51

Table 1: Statistical analyses of porosity versus formation factor and computed (m).

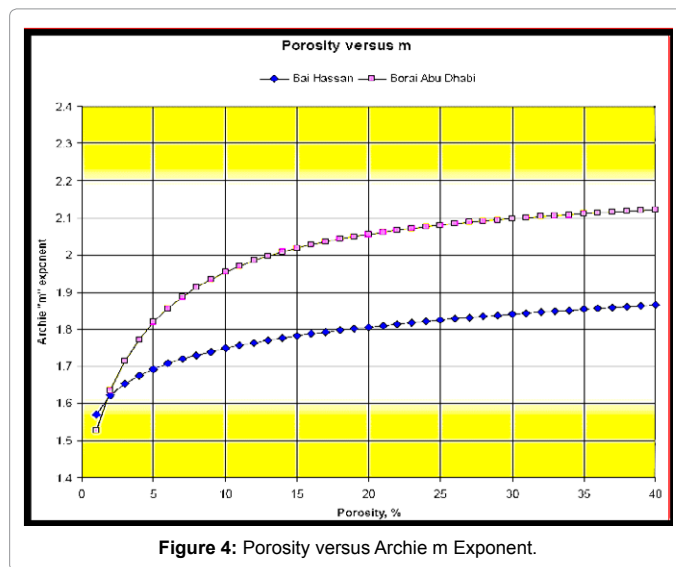


Figure 4: Porosity versus Archie m Exponent.

$$m = 1.5727 \phi^{0.467}$$

This study showed that for the available data set, “m” decreased as porosity decreased. This “m” trend impacted the saturation calculation by producing lower water saturation values at the lower porosity values than if a constant value of the “m” parameter had been used, for example a value such as 1.85 which is appropriate for porosity values in the mid-thirties.

The net effect increased the hydrocarbon pore volume slightly in the low porosity range. This trend of decreasing “m” as porosity drops has been observed elsewhere in carbonates and was documented for carbonate reservoirs in Abu Dhabi in a 1987 paper by Borai.

For comparison, the KF2 and Borai results are plotted together in the Figure 4. The equation from Borai’s work is:

$$m = \frac{2.2 - 0.035}{\phi + 0.042}$$

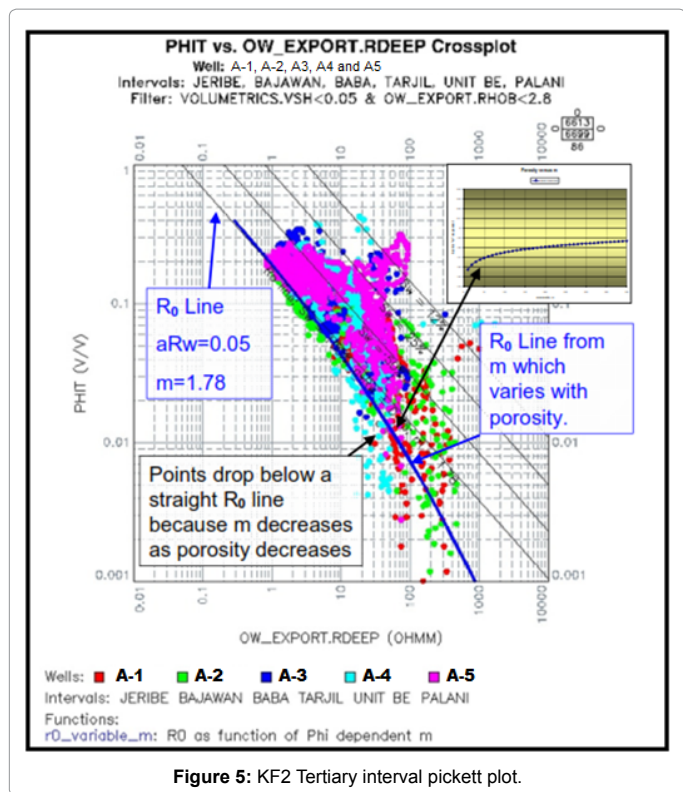
with porosity entered as decimal or v/v units

Based on the Archie “m” versus porosity regression, “m” has a value of about 1.78 in the 10% to 20% porosity range. This value of “m” was used for the slope of the R<sub>0</sub> line, the line of 100% water saturation on the Pickett plot of Figures 5 and 6.

Figure 5 is a Pickett plot, just a resistivity versus porosity cross plot on logarithmic scales, of five flank wells for the Tertiary interval. Flank wells were used in order to have data from the water leg to estimate formation water resistivity, R<sub>w</sub>.

This slope projects to a R<sub>w</sub> value of 0.05 ohmm at formation temperature when the line is set along the left edge of the cluster of points in the 10% to 20% porosity range, the R<sub>0</sub> line defines the resistivity response for 100% water saturation in the interpretation model. The other lines represent 50%, 25%, and 12.5% water saturation level S<sub>w</sub>.





Wells	Porosity	Permeability	Ro	Rw
A-1	16.5	2.35	2.06	0.05
A-2	19.5	12.90	1.51	0.05
A-3	2.01	16.98	1.43	0.05
A-3	15.99	2.21	2.13	0.05
A-4	15.02	2.02	2.56	0.05
A-5	17.02	2.28	2.90	0.05

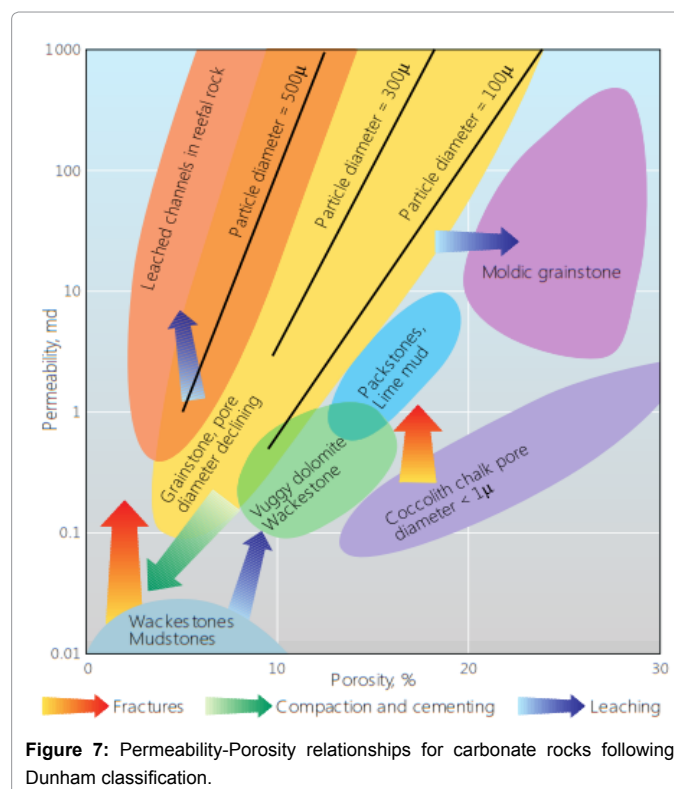
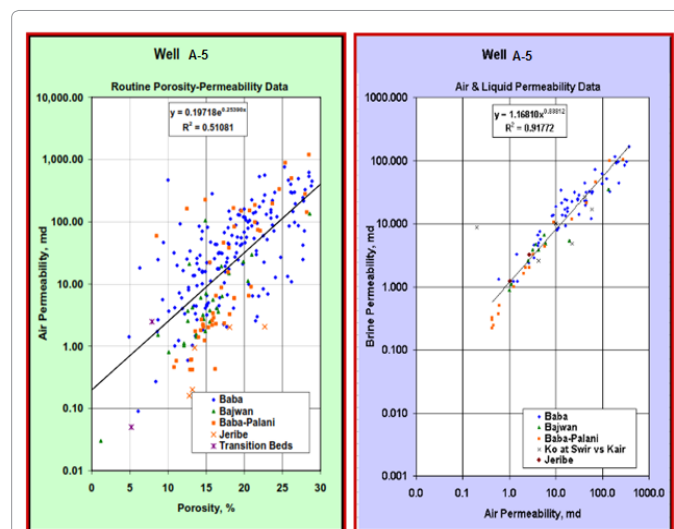
Table 2: Studied wells.

## Results and Interpretations

### Features of carbonate reservoir rocks

Geological features such as fractures, vugs and inter-crystalline structures all contribute hugely to the secondary porosity of carbonate reservoirs Table 2. It is important to be attentive of the particular features contributing to the porosity of a producing carbonate reservoir to be able to predict, evaluate and possibly enhance the reservoir production. Though these features of carbonate reservoir provide only a small amount of the total hydrocarbon pore space, they still enhance the reservoir to produce at economic rate [5-7]. The cementation exponent or lithologic exponent “m” is a major factor in defining the calculation of hydrocarbon or water saturation in heterogeneous carbonate reservoirs. Resistivity and petro-physical data solves this. It can be realized from the analysis that majority of the natural fractures that were generated during the depositional and diagenetic stage of the reservoir has suffered some form of geological changes such as leaching, dolomitization, recrystallization and cementation which probably cause of drilling and production activities. The gradient value, which implies the cementation exponent of, simply indicates an inter-crystalline enhanced porosity according to Archie’s porosity classification from Archie [8] and using Pickett plot shown in Figure 7. KF2 field analyses indicate further suffering diagenetic process during further production

over the years. The methods approved for oil recovery purposes would further result in leaching and dissolution of the inter-crystalline pores leading to vuggy solution porosity [9-12], which are usually more complex than either intergranular – intercrystalline or fracture porosity system. Classifying the carbonate rocks of KF2 oil field according to the Dunham classification plot (Figure 7), using effective porosity values derived from their permeability data suggests packstone lime, mudstone and some moldic grainstones. This been inferred on the plot on thus confirming the textural properties and grain size of the study area [13-15].



The analysis from Figure 7 shows that about 80% of the observed lithofacies in wells of KF2 oil field are packstone, with some traces of mud, clay and fine silt size carbonates. Therefore explains a gradual change in the original grainstones and packstone structure of the reservoir at the time of deposition as earlier explained by Majid and Veizer [16]. Other wells observed however indicate moldic grainstones which is a sharp deviation from the original depositional facies of the reservoir and therefore verifies the dissolution of a pre-existing constituents of the KF2 carbonates through the various drilling and production activities over the years.

### Carbonate formation studied

The variability and heterogeneity features of carbonate reservoir from pore to reservoir scale create a significant problem covering data acquisition, petrophysical evaluation and consequently reservoir description [9]. They further explained that the variation in properties of Carbonate facies and their pore character often control the distributions of net pay, porosity and hydrocarbon saturation. Generally, pore character rules carbonate reservoir quality, which is different in sandstone reservoir where variations in mineralogy, grain-size distribution and sorting, texture and degree of indurations governs the reservoir quality [10-12].

From the above stated, it is authoritative that diagenetic activities such as compaction, cementation, dolomitization, dissolution and leaching which have a significant effect on the pore structure are minimized by using efficient drilling and production techniques. However, it is important to note that diagenetic activities such as dissolution and leaching could either enhance or decrease the connectivity or permeability of the pores in a carbonate reservoir. Drilling activities such as the effect of drilling bits, reactions from the combination of drilling fluids with reservoir fluids and well completion activities could also destroy the natural micro-pores of a carbonate reservoir, dissolve the inherent fractures in the reservoir and hence reduce the connectivity of the pores or further destroy the inter-crystalline structure. All these will reduce the flow rate in the reservoir and consequently decrease the performance and production rate of the well. KF2 oil field is presently suffering some form of petrophysical changes because of dissolution and leaching of the natural fractures that formed originally with the reservoir at deposition. This will consequently reduce the pore connectivity, flow rate of the hydrocarbon fluids and the production of the oil field.

### Conclusions

Fractures and vugs usually contribute to the secondary porosity of carbonate reservoirs thus creating a dual or sometimes triple porosity model for carbonate rocks in addition to the primary porosity derived from the matrix structure of the rock. Carbonate reservoir generally are either fractures or non-fractured (tight) during sedimentation, further diagenetic activities after sedimentation results in the formation of some of these micro-pore features. The cementation exponent "m" of a carbonate reservoir as well as data obtained from wireline logs are usually been used with Archie's equation to distinguish these features. This study has however further shown that these features changes

from the natural fractures to complex vugs overtime as the reservoir ages and the production years increases. It is therefore necessary that production engineers adopt production and recovery techniques that will preserve the natural fractures that were formed during deposition and sedimentation period of the reservoir.

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