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The Porosity Comparison of Upper Fars Sandstone for different Outcrops, in Duhok Province Kurdistan Region of Iraq

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I. SUMMARY

The aims of this work are to determine the porosity and characteristics of Upper Fars Formation sandstone for different outcrops, in Duhok Province, Kurdistan Region, Iraq, by using the liquid saturation method. These analyses were used to get some porosity data and ultimately to compare the Upper Fars Sandstone porosity for the three different locations in Duhok province.

It is proposed that the Sandstone of the Upper Miocene Injana formations from northern Iraq were deposited in a relatively unstable tectonic environment. Sediments were derived mainly from the ophiolitic–radiolitic successions in north and northeastern Iraq as well as recycling from older sedimentary formations. This led to a mixed tectonic signature for the sandstones, with a predominant recycled/transitional arc sediment setting.

Several diagenetic processes have an effect on the Injana sandstones. Compaction, cementation, and recrystallization generally lead to reduction of the primary porosity, while dissolution and alteration may lead to increase porosity by creation of secondary porosity.

The porosity results are revealing the good studied section porosities and to be able to hold sufficient amount of hydrocarbon which enable it to be a good reservoir, and had been enhanced by some diagenetic processes especially, dissolution, alteration and later followed by secondary effects from tectonics activities.

II. INTRODUCTION

This paper starts with a general survey and then examines the petrography of the Injana Formation in, Duhok province, Kurdistan Region, Iraq, as implications for provenance porosity of sandstone (Upper Fars Formation). The Upper Fars Formation was originally described in the Fars Province of Iran by Busk and Mayo (1918), but without a type locality in Iraq (van Bellen et al. 1959). Accordingly, Jassim et al. (1984) proposed the name Injana Formation to replace the Upper Fars Formation in Iraq and defined a subsidiary type section near Injana, at Jabal Hemrin (near the old police station along Baghdad-Kirkuk Highway, 120 km NE of Baghdad). This recommendation was published by Al-Rawi et al. (1992) and adopted by other authors (e.g., Jassim and Buday 2006) and herein. The Upper Miocene Injana Formation exists in Iraq widely; it also extends into northern Syria, Turkey, and over large areas in southern Iran (van Bellen et al. 1959; Jassim and Buday 2006; Fig. 1a). It is basically described as subcontinental to continental coarse and medium-grained carbonate-rich sandstone alternating with brownish red siltstones, mudstones, and marls with rare freshwater limestone (van Bellen et al. 1959; Jawad Ali et al. 1988; Figs. 1 and 2). Because of its wide distribution, the Injana Formation has been described in numerous papers, books, reports, and academic dissertations (e.g., van Bellen et al. 1959; Basi 1973; Yakta 1976; Yaqub 1977; Al-Sammarai 1978; Buday 1980; Al-Banna 1982; Al-Maroof 1986; AlKurukji 1989; Othman 1990; Al-Juboury 1994; Al-Fattah 2001; Al-Haidary 2003; Al-Rashedi 2005; Mahdi 2006; Jassim and Buday 2006 and many others), the majority of which focused on geological overviews of the formation and/or provided descriptions of its lithofacies, sedimentology, and depositional environment.

It is proposed that the carbonate-rich lithic arenites of the Upper Miocene Injana formations from northern Iraq were deposited in a relatively unstable tectonic environment. Sediments were derived mainly from the ophiolitic–radiolitic successions in north and northeastern Iraq as well as recycling from older sedimentary formations. This led to a mixed tectonic signature for the sandstones, with a predominant recycled/transitional arc sediment setting (Al-Juboury, 2009).

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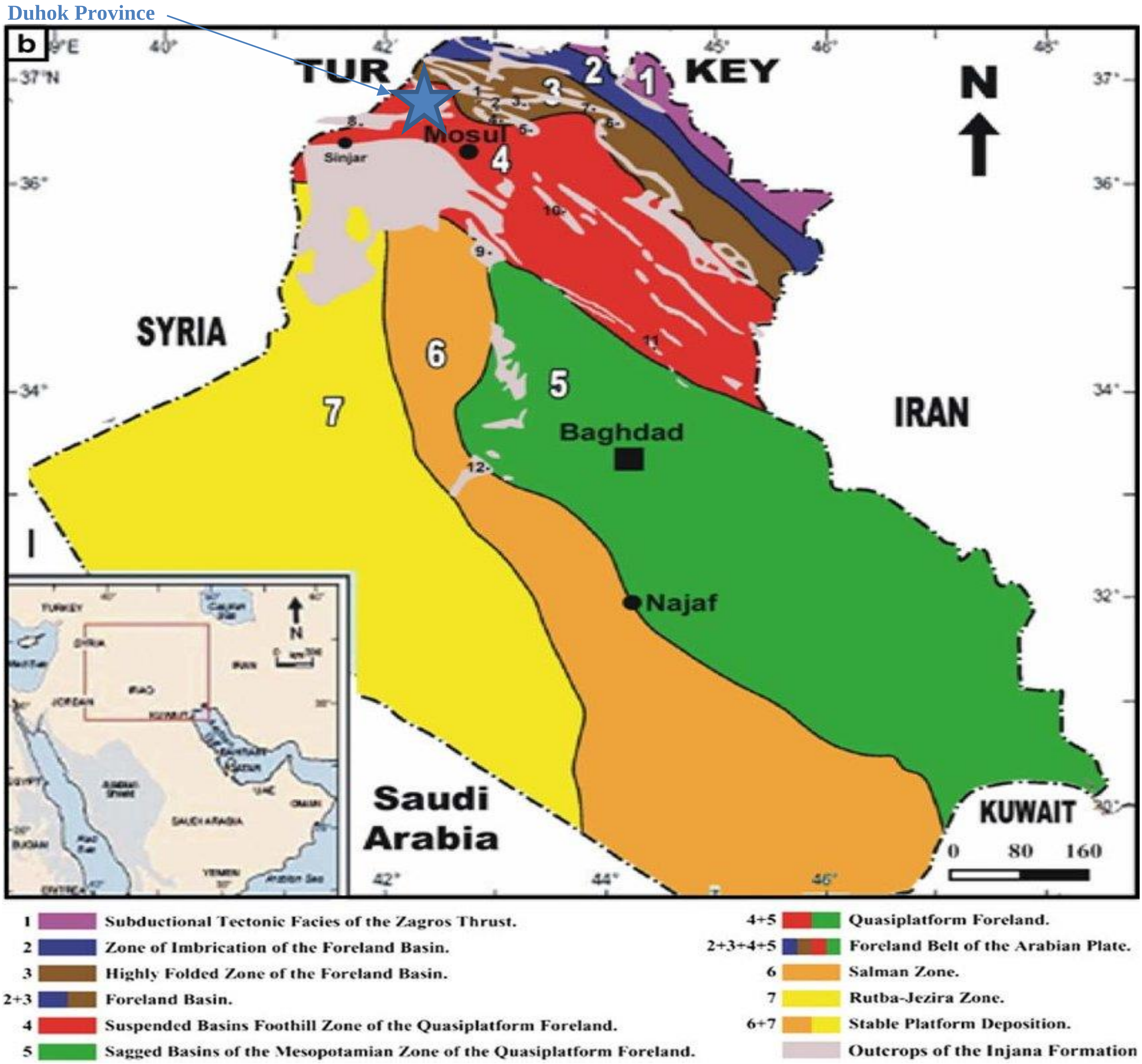

Fig. 1: Study Area (Duhok Province)

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III. SAMPLING AND METHODOLOGY

The present study takes into consideration 3 sections in Duhok Province (Aloka Section, Koret Gavana section and Dolly section) were studied in detail. From these sections, 24 samples were collected from the sandstones for petrographic, and porosity measurement.

Total porosity is defined as the fraction of the bulk rock volume V_b that is not occupied by solid matter. Porosity is a measure of storage capacity of a reservoir. It is defined as the ratio of the pore volume to bulk volume, and is may be expressed as either a percent or a fraction. In equation form:

$$\phi = \frac{Vb - Vg}{Vb} = \frac{Pore\ Volume}{Total\ Bulk\ Volume}$$

It should be noted that the porosity does not give any information concerning pore sizes, their distribution, and their degree of connectivity. Thus, rocks of the same porosity can have widely different physical properties. An example of this might be a carbonate rock and a sandstone. Each could have a porosity of 0.2, but carbonate pores are often very unconnected resulting in its permeability being much lower than that of the sandstone.

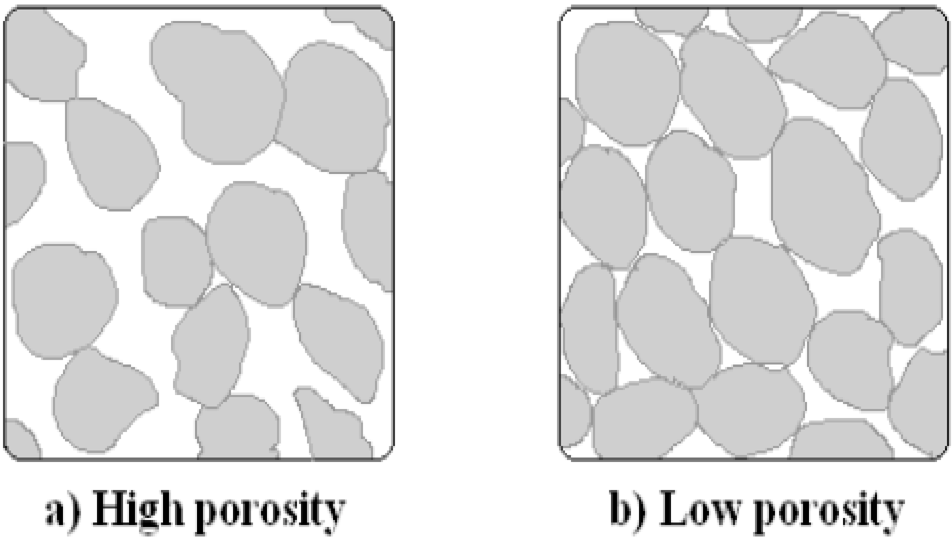

Fig. 2: The porosity conditions

IV. TYPES OF POROSITY

Several diagenetic processes have an effect on the Injana sandstones. Compaction, cementation, and recrystallization generally lead to reduction of the primary porosity, while dissolution and alteration may lead to increase porosity by creation of secondary porosity (Boggs 1997). The pores are distinguished as a result of dissolution of feldspars and lithic fragments (mainly carbonate) as intergranular porosity (Al-Jubory, 2009). Porosity is a selective one after partial or complete dissolution of fossil remains. This type leads to formation of moldic porosity if it is complete. The later type is limited to sandstone units in the lower part of Injana Formation which is believed to be deposited under tidal flat, lacustrine, and shallow marine environments where some fossils occasionally occurred. Secondary porosity in the Injana Formation occurs mainly in the mesodiagenesis and telodiagenesis stages of diagenesis (sensu, Choquette and Pray 1970).

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In the mesodiagenetic stage, the dissolution of unstable grains occurs mainly through pore fluid and result in selective destruction of grains, whereas in telogenetic stage, uplifting and surface weathering through meteoric–water interaction results into dissolution of carbonate cement and dissolution of feldspar and unstable minerals (pyroxenes and amphiboles) which in general led to formation of secondary porosity. Therefore, porosity enhancement was probably caused by the combined effect of acidic meteoric and connate water during Upper Miocene by subarial exposure to erosion.
It should be noted that if the bulk volume and dry weight, or the bulk volume, saturated weight and porosity of a rock sample is known, then the grain density can be calculated. This parameter is commonly calculated from the data to compare the results with the known grain densities of minerals as a QA check. For example, the density of quartz is 2.65 g/cm^3, and a clean sandstone should have a mean grain density close to this value.

Porosity in rocks originates as primary porosity during sedimentation or organogenesis and as secondary porosity at later stages of the geological development. In sedimentary rocks, the porosity is further classified as intergranular porosity between grains, intragranular or intercrystallite porosity within grains, fracture porosity caused by mechanical or chemical processes, and cavernous porosity caused by organisms or chemical processes. Solid rock is often not so solid. Sandstone might have started out as a sand dune or a beach, which got buried and compressed. But spaces remain between the particles. These spaces, or pores, are where oil and gas may be found. If you look at a sponge, you can see many open spaces. Sandstone is like that, only the spaces are generally much smaller, so small that they cannot be seen without a microscope. Pore diameters larger than 0.06 mm are called macropores and those less as micropores.

Rock grains are of different sizes, shapes and mineralogical composition. They are bound into a more or less dense structure. Among these grains, we can always find voids, which indicates that some rocks can be justly considered a porous material. These voids are filled with gas, oil, or water, or with gas, oil and water. Porosity varies from less than 10% to greater than 40% in sandstones.

Absolute porosity and Effective porosity

Many geologists and petroleum engineers recognize two types of porosity: **Total porosity**, also referred to as physical or absolute porosity, equivalent to the ratio of all the pore spaces in a rock to the bulk volume of the rock, regardless of whether they are isolated or intercommunicative;

$$\varphi_{Total} = V_{Total}/Vb$$

Effective (useful or dynamic) porosity, is the ratio of interconnected void spaces to the bulk volume. (i.e., immobile fluid retained by capillary forces in minute pores, crevices, and cracks).

$$\varphi_{effective} = V_{interconnected}/Vb$$

Control on Porosity

The initial porosity is affected by three major microstructural parameters. These are grain size, grain packing, particle shape, and the distribution of grain sizes. However, the initial porosity is rarely that found in real rocks, as these have subsequently been affected by secondary controls on porosity such as compaction, cementation and geochemical diagenetic processes. This section briefly reviews these controls.

The increase in the porosity only becomes significant at grain sizes lower than 100 micron and for some recent sediments porosities up to 0.8 have been measured. as grain size increases past 100 micron, the frictional forces decrease and the porosity decreases until a limit is reached that represents random frictionless packing which occurs at 0.399 porosity, and is independent of grain size. No further loss of porosity is possible for randomly packed spheres, unless the grains undergo irreversible deformation due to dissolution-recrystallisation, fracture, or plastic flow and all such decreases in porosity are termed compaction.

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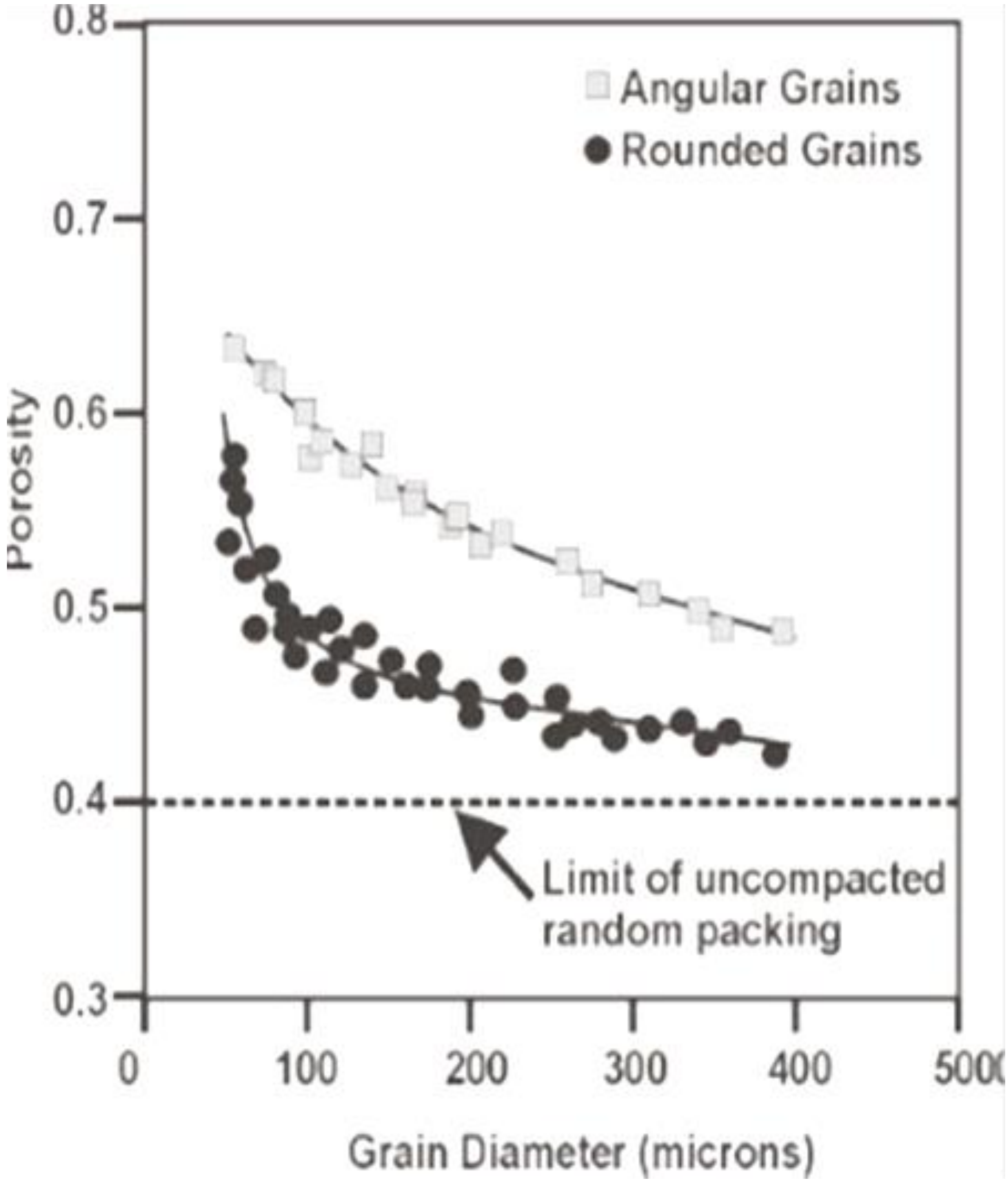

Fig. 3: Porosity and grain size relation

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V. POROSITY MEASUREMENT

A great many methods have been developed for determining porosity, mainly of consolidated rocks having intergranular porosity (encountered in oil reservoir). From the definition of porosity, it is obvious that common to all methods is the need to determine two of three volumes: total or bulk volume of the sample, its pore volume, and/or the volume of its solid matrix. The various methods based on such volume determination, called “direct methods”, differ from each other in the way these volumes are determined. Other methods are available, called “indirect methods” based on the measurement of some properties of the void space. Examples of such properties are the electrical conductivity of electrically conducting fluid filling the void space of the sample, or the absorption of radioactive particles by a fluid filling the void space of the sample.
Porosity of a rock is the fraction of the volume of space between the solid particles of the rock to the total rock volume. The space includes all pores, cracks and vugs. The porosity is conventionally given the symbol(ϕ), and is expressed either as a fraction varying between 0 and 1, or a percentage varying between 0% and 100%. Permeability and porosity of a rock are interrelated as higher porosity implies higher permeability (Sadeq and Yusoff, 2015).
The measurement of porosity is important to the petroleum engineer since the porosity determines the storage capacity of the reservoir for oil and gas. The understanding of petrophysical and multiphase flow properties is essential for the assessment and exploitation of hydrocarbon reserves; these properties in turn are dependent on the geometric and connectivity properties of the pore space. It is necessary to distinguish between the types of porosity because in porous rocks there will always be a number of blind or unconnected pores. This work is achieved through field observation and laboratory work.
There are many methods of measuring the porosity (mercury porosimetry, helium porosimetry, buoyancy, and fluid saturation). In this work the saturation method was used. Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity. For example, if the porosity of a rock sample was determined by saturating the rock sample 100% with a fluid of known density and then determining, by weighing, the increased weight due to the saturating fluid, this would yield an effective porosity measurement because the saturating fluid could enter only the interconnected pore spaces (Tarek, 2006).

VI. CALCULATIONS AND DISCUSSION

The saturation method is used to measure the porosity of the rock, firstly, by removing the weathered parts, cleaning and drying the rock, then weighing it in its dry state to give the dry weight. Afterward, the rock is fully saturated and weighed then the bulk volume of the rock is calculated.

$$\textbf{Porosity} = \frac{\textit{void volume}}{\textit{bulk volume}} * 100$$

$$\textbf{Porosity} = \frac{\textit{bulk volume} - \textit{grain volume}}{\textit{bulk volume}} * 100$$

$$\textbf{Porosity} = \frac{\textit{pore volume}}{\textit{pore volume} + \textit{grain volume}} * 100$$

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Table 1. The porosity ranges in Sandstone in the studied section areas.

No. of Sample	Section Areas	Porosity %
1	Aloka	22.7
2	Aloka	20.3
3	Aloka	19.6
4	Aloka	21.4
5	Aloka	18.6
6	Aloka	18.2
7	Aloka	19.2
8	Aloka	20.7
9	Koret Gavana	23.2
10	Koret Gavana	21.4
11	Koret Gavana	21.8
12	Koret Gavana	20.7
13	Koret Gavana	22.3
14	Koret Gavana	20.9
15	Koret Gavana	19.8
16	Koret Gavana	22.5
17	Dolly	27.3
18	Dolly	26.4
19	Dolly	26.8
20	Dolly	25.2
21	Dolly	26.3
22	Dolly	25.0
23	Dolly	24.5
24	Dolly	24.1
		Average porosity 22.45

Extensive field work was done in the Duhok Province Upper Fars Sandstone (Aloka Section, Koret Gavana section and Dolly section) in order to study the geological characteristics and choose the appropriate outcrop sections to make sure that the samples were carefully collected to be ideal representing of this studied different sections of Sandstone for sampling and description.
As determining reservoir properties accurately is important, and one of the most important things is porosity, which can be used to calculate the total hydrocarbon volume present in the reservoir. Hydrocarbon volume in the reservoir equals pore volume, and we should have a good understanding of pore types due to engineering and geological point view, also the factors that affecting porosity of each rock. The porosity can be increased by fracturing the formations in enhanced oil recovery, by enlarging the pores which increase the permeability, and effect the flow rate and production rate of the reservoir.

The Upper Fars Sandstone Duhok Province porosity values range between (18.2 and 27.3 %), with an average rate of 22.45 %. The changes in the porosity values may due to the difference in the condition of depositional environment from place to another place, many other factors may incorporate in this change. Several diagenetic processes have an effect on the Injana sandstones. Compaction, cementation, and recrystallization generally lead to reduction of the primary porosity, while dissolution and alteration may lead to increase porosity by creation of secondary porosity.
However, the results are revealing the good porosities for the studied section areas, and had been enhanced by some diagenetic processes especially, dissolution, alteration and later followed by secondary effects from tectonics activities.

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VII. CONCLUSION

The reservoir should have a body rock that has good porosity to contain oil and gas (hydrocarbon), and sufficient permeability to permit the fluid movement (migration. The reservoir must contain hydrocarbons in commercial quantities, and there must be some natural driving force within the reservoir, usually gas or water, to allow the fluids to move to the surface.
The results are revealing the good porosities for the studied section areas and to be able to hold sufficient amount of hydrocarbon which enable it to be a good reservoir, this had been enhanced by some diagenetic processes especially, dissolution, alteration and later followed by secondary effects from tectonics activities.

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