Tikrit Journal of Pure Science 21 (3) 2016 *ISSN: 1813 – 1662 (Print)*
E-ISSN: 2415 – 1726 (On Line)

Upper Palaeogene-Lower Neogene Reservoir Characterization in Kirkuk, Bai Hassan and Khabaz Oil Fields, Northern Iraq

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Abstract

The Upper Palaeogene-Lower Neogene succession represent subsurface sections from Kirkuk, Bai Hassan, and Khabaz oilfields were divided to many reservoir units dependent on information derived mainly from petrographical description, well log analysis, and related microfacies. In Khabaz oil Field, the hydrocarbon reservoir includes three reservoir units covered the Jeribe Formation, Anah Formation with its interfingering zone with Azkand Formation and Azkand Formation, the total thickness of this reservoir reaches up to (128 m) with net pay thickness of about (85.7 m) and net average porosity of (0.096) while the net water saturation is (0.185), the volume of shale is (7.130). The hydrocarbon reservoir in Bai Hassan was represented by three reservoir units comprised from the Bajwan and Baba formations, the total thickness of this reservoir is (178 m) with net pay thickness of (154.2m) and net average porosity of (0.121) while the net saturation is (0.156), the volume of shale is (36.837). Four reservoir units comprised the hydrocarbon reservoir in Kirkuk Field where they covered the Bajwan, Baba, Shurau and Sheikh Allas formations. The total thickness of these reservoirs is (136 m) with net pay thickness (124.5m) and net average porosity (0.178) while the net water saturation is (0.159), the volume of shale is (5.82). Many types of porosity were associated with these reservoirs such as the interparticles, intraparticles, intercrystaline, fracture, channel, moldic, vug, and cavern porosities. These porosities are attributed to a combination of dolomitization, fracturing, and dissolution.

Key words: Reservoir characterization, well log analysis, microfacies, porosity, Upper Palaeogene-Lower Neogene succession, Kirkuk Oil Fields.

Introduction

Seven subsurface sections have been selected from wells of three oil fields located in Kirkuk governorate northern Iraq. For this purpose more than 236 thin sections were described and interpreted, some of them were previously prepared by the North Oil Company (NOC). All these thin sections were studied petrographically by applying classification mentioned in [1] and its modified version as presented in [2]. In addition, different logs including Gamma Ray log (GR), Compensated Neutron log (CNL), Formation Density Compensated log (FDC), Borehole Compensated log (BHC), and Resistivity logs were analyzed by using softwares like the interactive petrophysics (IP) and Log Plot programs which compared the petrographic description and microfacies study to evaluate the physical properties, reservoir characterizations and determine the average porosity that calculated by Computer processing Information (CPI), water saturation (S_W), hydrocarbon saturation (S_h), the movable oil saturation (MOS), the residual oil saturation (ROS) and the net pay thickness in addition to the volume of shale. Also, net porosity ($Ø_{Net}$) and net water saturation (SW_{Net}) were calculated which benefit mapping the future studies. The well logs used for the present study include KZ.23 (Khabaz-23), KZ.29 (Khabaz-29) Wells of Khabaz Field, BH.90 (Bai Hassan-90) Well in Kithka dome of the Bai Hassan Field and K.218 (Kirkuk-218) Well in Baba dome of the Kirkuk Field in addition to K.227 (Kirkuk-227) Well, K.243 (Kirkuk-243) Well, and BH.138 (Bai Hassan-138) Well where the latest three wells were used for petrographical study with the previous wells. The offshore facies of the Palani Formation underlies the reservoir units in K.218 and BH.90 wells whereas the facies of the Ibrahim Formation bounded the reservoir units in both KZ.23 and KZ.29 wells. On the other hand they were capped by the facies of the Fatha Formation in all studied wells.

The location of the study area has been chosen due to the information available about the selected wells such as rock samples, thin sections and final well reports as well as the different well logs. Kirkuk structure has a length of more than (100 km) and about (4-5km) in width. To the south west of this field, and to the northwest of Kirkuk city, Bai Hassan structure is located, it has (28 km) in length and (3 km) in width, while Khabaz structure lies to the southwest of Baba dome/Kirkuk Field about (12 km) from Kirkuk city, its length is (20 km) and it has (5 km) width (Fig.1). The study area is located between

	Geographic Coordinates	UTM Coordinate
Eastern	(43° 50' 38.7586") to (44° 33' 27.5240") =	(395000) to (460000) m
Northern	(35° 22' 20.6665") to (35° 44' 16.0373") =	(3915000) to (3955000) m

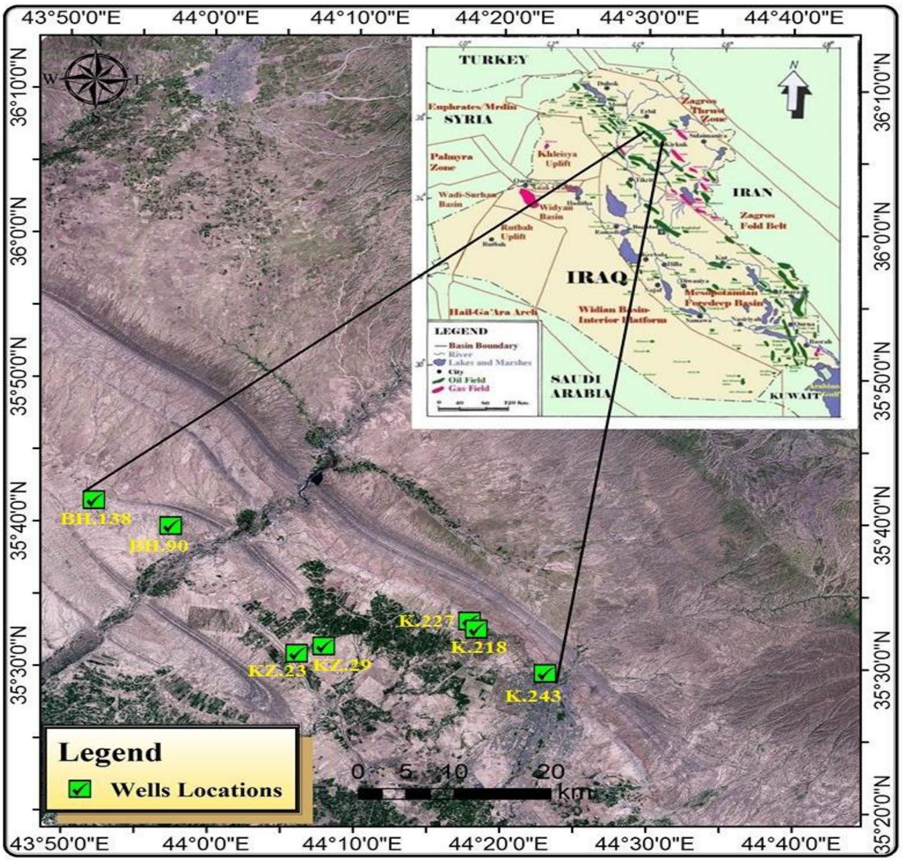

Figure 1: Location of studied area

Geologic setting of the Study Area

Kirkuk, Bai Hassan and Khabaz fields are located in Butmah-Chemchamal Subzone within Foothill Zone part of Unstable Shelf (Fig.2). These are characterized by longitudinal anticlines trending northwest-southeast which formed as a result of Alpine orogeny in the last of Tertiary age detached by wide syncline with thick deposits cover [3], therefore these fields are trending northwest-southeast within the framework of Zagros folds extent.

Kirkuk Field which plunges by Tarjil plunge in the distal southeast includes three major domes from southeast to northwest (Baba, Avanah and Khurmalah domes), indeed subjoin to it (Zab dome) as the fourth dome. Baba and Avanah domes are separated by Amsha Saddle near the Lesser Zab River, while Avanah and Khurmalah domes are separated by Daibaga Saddle. Bai Hassan Field includes two domes (Kithka dome in the southeast and Dauod dome in the northeast), Kithka dome is larger and more important than Dauod dome. Khabaz Field is asymmetrical subsurface fold where the northeast flank is steeper than its southwest flank [4].

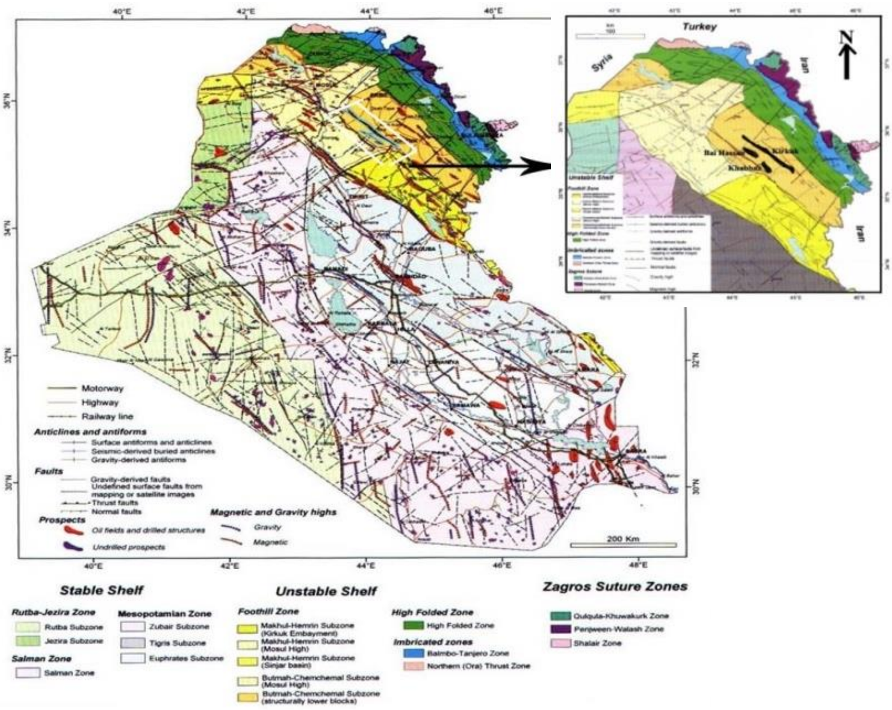

Figure 2 Tectonic Classification of Iraq, modified after [3]

Porosity

Porosity is considered the most important characteristic of reservoir rocks related with diagenetic process and burial depth. The porosity may be primary that forms contemporaneously with deposition, or secondary forming by diagenesis [2]. Eight types of porosity are distinguished within these facies in six selected wells from the studied oil fields according to the classification of porosity by [5], they are: Intraparticle porosity which forms as a result of dissolving or tearing out the particles due to diagenetic and it is abundant within Bajwan Formation (Fig. 3-A, Fig. 3-B); Intercrystalline porosity which coupled with dolomitization and recrystallization diagenetic process [6], this type is distinguished within Sheikh Allas, Baba and Bajwan formations (Fig. 3-C); Fracture porosity, this type of secondary porosity forms as fractures due to compaction and tectonism, and it is identified in Baba, Bajwan, Azkand rather than Jaddala, Palani and Ibrahim formations with rare extent (Fig. 3-D); Channel porosity which occurs as longitudinal voids sometimes filled with sparry calcite cement, it is recognized within Shurau, Baba, Bajwan, Azkand and Jeribe formations, and with regardless occurrence within Palani Formation (Fig.4-E, Fig.4-F); Moldic porosity forms due to selective dissolution of fossil's skeleton. It is found in Sheikh Allas, Baba and Bajwan formations as well Tarjil Formation but with regardless intensity (Fig.4-A, Fig.4-B,); Vuggy porosity which is characterized by voids resulted from dissolving of groundmass. This type is identified within Shurau, Baba, Bajwan, Azkand and Jeribe formations (Fig.4-C, Fig.4-D,); Cavern porosity which applies to man-sized or larger pores of channel or vug shapes [5], this type of porosity is distinguished within Shurau, Baba and Bajwan formations (Fig. 4-E, Fig.4-F). Interparticles porosity which represents microporosity exist between the particles forming as primary porosity, it has scarcely occurrence within Shurau and Bajwan formations (Fig. 4-G, Fig. 4-H).

Influence of the diagenesis on the porosity of studied successions

The petrographic study of the Upper Palaeogene-Lower Neogene successions in the six selected wells shows that the rocks of these successions were affected by many type of diagenetic process with different degrees. The diagenetic process which affected the rocks of successions also affected on the porosity through increasing or reducing it, Compaction caused packing the grains and reducing the pore-space between grains, this reduction in porosity is more effective by burial [7] likewise the reduction in permeability is more sensitive with compaction [8], the effective stress that result by compaction corresponds to about 1 km without overpressure (more than 3 km depth) which is very important in reducing both mechanical compaction and pressure dissolution [9] whereas open fractures resulted by compaction or tectonism forms passage for solutions which dissolve the host rocks but the filled fractures (veins) prevent transportation of these solutions [10]. Leaching is one of the most important processes giving rise to secondary porosity through dissolving the weakly resistant grains and forming secondary voids within the groundmass or event within grains [11]. Anhydrite is found associated with

ISSN: 1813 – 1662 (Print)
E-ISSN: 2415 – 1726 (On Line)

the secondary voids resulting by dissolution and this association caused closing these voids and reducing the porosity [12]. Neomorphism can lead to either increasing or unaltered porosities [11]. Cementation reduces the porosity by filling the pores, fractures and molds. Dolomitization above all play an important role with increasing and improving the porosity that cause intercrystalline porosity but with progression of dolomitization at last stages it decrease the porosity [13].

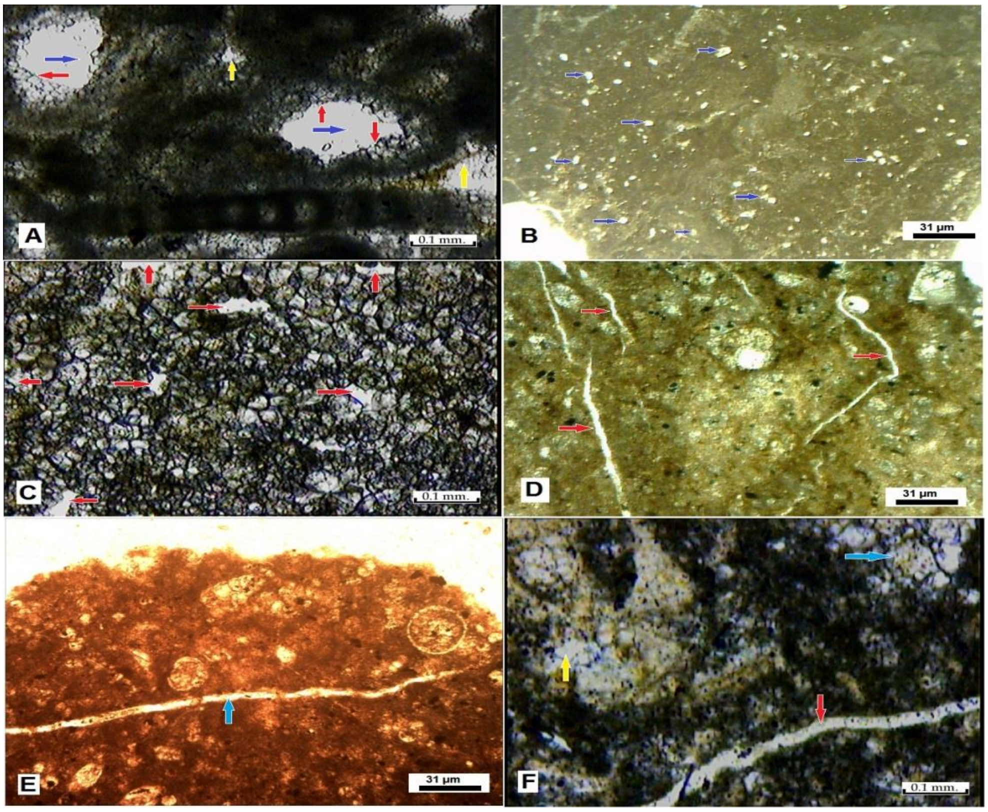

Figure 3

A. Intraparticles porosity (blue arrows) with cement growth inside the pores (red arrows), and interparticles porosity (yellow arrows); Bajwan Formation, K.227 Well, Depth 372 m, PPL.
B. Intraparticles porosity (blue arrows); Bajwan Formation; BH.138 Well, Depth 1244 m, PPL.
C. Intercrystalline porosity (red arrows) coupled with recrystallization diagenesis; Baba Formation, K.243 Well, Depth 545 m, PPL.
D. Fracture porosity due to compaction diagenesis (red arrows); Palani Formation, BH.138 Well, Depth 1450 m, PPL.
E. Channel porosity (blue arrow) with micrite matrix; Palani Formation; BH.90 Well, Depth 1108 m, PPL.
F. Channel porosity (red arrow) with macrosparite (blue arrow) and dissolution (yellow arrow); Bajwan Formation; K.227 Well, Depth 396 m, PPL.

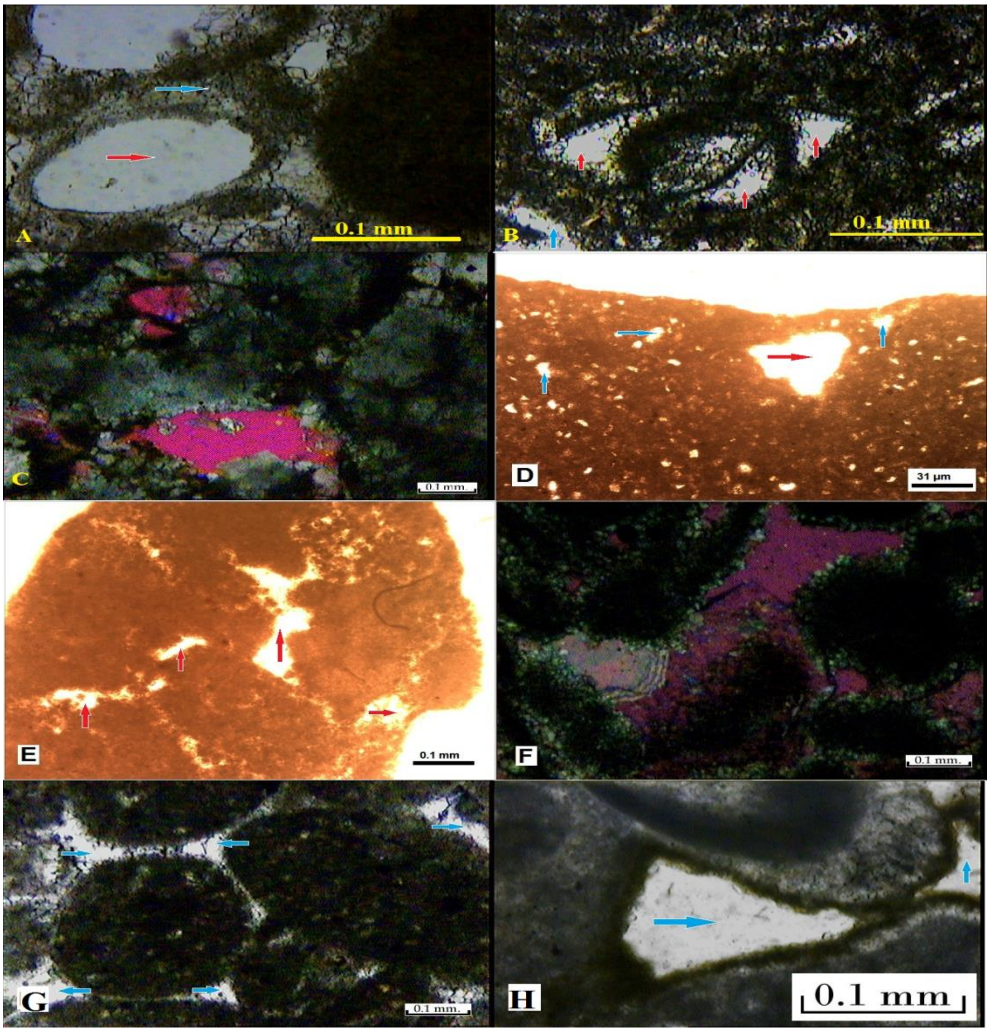

Figure 4

A. Moldic porosity due to selective dissolution with extended meteoric diagenesis and complete fabric inversion where the former grains became secondary pores (red arrow)and the former (primary) pores became cement filled (blue arrow); Baba Formation; K.227 Well; Depth 413 m, PPL.
B. Moldic porosity (red arrows) and vug porosity (blue arrow) due to selective dissolution; Baba Formation, K.227 Well, Depth 418 m, PPL.
C. Vug porosity resulted from dissolving of groundmass; Bajwan Formation, K.243 Well; Depth 531 m, XPL.
D. Vug porosity resulted from dissolving of groundmass (red arrow) and intraparticles porosity (blue arrows) with micrite matrix; Jeribe Formation, BH.90 Well; Depth 884 m, PPL.
E. Cavern porosity resulted from dissolving of groundmass (red arrows) with micrite matrix; Baba Formation; BH.90 Well; Depth 972 m, PPL.
F. Cavern porosity resulted from dissolving of groundmass with recrystallization; Bajwan Formation; K.227 Well; Depth 373 m, XPL.
G. Interparticles porosity (blue arrows); Bajwan Formation, K.243 Well, Depth 533 m, PPL.
H. Interparticles porosity (blue arrows); Bajwan Formation, K.227 Well, Depth 373 m, PPL.

Well Logs

Well logs were employed for facies analyses (lithology, porosity, fluid evaluation [14]. They were used to determine reservoir characterization and petrophysical properties, they are: 1. Resistivity Logs were used to determine hydrocarbon versus water-bearing zones, It indicates permeable zones and determine resistivity porosity [15]. Resistance depends primarily on the pore liquid and its salt content [9]. When the formation is porous and contains salty water the overall resistivity will be low while it will be very high when the same formation contains hydrocarbons, therefore a high resistivity values may indicate a porous, hydrocarbon-bearing formation [16]. Two types of resistivity logs were used in this study including; Dual Laterolog (DLL) which record the resistivity of strata in ohm per meter unit was developed to provide accurate readings of formation resistivity in holes drilled with salt water muds [17]. It includes a deep reading resistivity device (R_{LLd}) which used in determining the true resistivity (Rt) and a shallow reading device (R_{LLs})

which record the invasion resistivity (Ri) in the area invaded by mud filterate (invaded zone) [15]. The use of Dual Laterolog measurement is better if (R_{xo}) is lower than (Rt) [18], and Microspherically Focused Log (MSFL) which is considered a pad type, focused electrode that has very shallow depth of investigation, and measure resistivity of the flushed zone (R_{xo}) [15]. The pad device can only be run in holes with conductivity drilling mud [16]; 2. Porosity Logs include Formation Density compensated Log (FDC) which measures the porosity by measuring the electronic density of the rock in (g/cm³) unit [17], two separate density values were used by the density log they are the bulk density (ρb or RHOB) which represent the density of the entire formation (solid and fluid parts) as measured by the logging tool where the measured electronic density represent the bulk density [19] and the matrix density (ρ_{ma}) which represent the density of the solid framework of the rock, porosity can derived from the bulk density of clean liquid-filled formations when the matrix density (ρ_{ma}) and the density of the saturating fluids (ρ_f) are known [20]; Compensated Neutron Log (CNL) that measures the hydrogen concentration in a formation and gives the porosity directly [21]. In shale-free formations where the porosity is filled with water or oil, the neutron log measures liquid filled porosity (φN) [20], older neutron logs were scaled in counts, but modern neutron logs are recorded in apparent porosity units with respect to a given mineralogy, Calcite is commonly chosen as a default mineral, in which case the porosity values will be true porosities in limestone zones, where zones are not limestone then the limestone equivalent neutron log should be rescaled to the zone matrix mineral or combined with density limestone equivalent porosity in an estimate of the true porosity [17], because the concentration of the hydrogen in both oil and water is nearly equally while the gas has low concentration of hydrogen, the log gives similar values for oil and water while it gives low values for gas [22], for the purposes of formation evaluation the neutron log is used in combination with the density log for porosity and lithology determination [23]; and Sonic Log which measures the interval transit time (Δt) of a compressional wave traveling through one foot of formation in (μsec/ft) unit [23], the interval transit time (Δt) is dependent upon both lithology and porosity and fluid content [22], in this technique interval transit time are recorded of clicks emitted from one end of the sonde travelling to one or more receivers at the other end, the sound waves generally travel faster through the formation than through the borehole mud [22], the borehole compensated sonic (BHC) log will give an indication of secondary porosity, if sonic porosity is considerably less than porosity from the density or density-neutron logs, the difference is usually attributed to fractures or fracture porosity [24]; 3. Gamma Ray Log which is simply indicate the degree of strata radioactivity in (API) unit which is generally proportional to the shaliness of the rocks and/or the amount of organic matter in the formation [14] and it is useful in identifying the lithology and making stratigraphical correlation [15], it is particularly useful in distinguishing clean and shale successions [25] where the Shale-free sandstones and carbonates have low concentrations of radioactive material and give low gamma ray readings, as shale content increases, the gamma ray log response increases because of the concentration of radioactive material in shale [20] and the presence of high amount of shale in the reservoir rocks giving inaccurate values of porosity and water saturation on porosity logs and resistivity logs [26], abrupt changes in gamma-ray logs response are commonly related to sharp lithological breaks associated with unconformities and sequence boundaries [27].

Logs interpretation

In this study the previous well logs for four boreholes in Khabaz, Bai Hassan and Kirkuk Fields were analyzed and their data were employed in estimating the reservoir characterization by using softwares like the interactive petrophysics (IP), Log Plot and Neuralog. Information were plotted in figures and arranged in tables then the average porosity ($Ø_{average}$) calculated by Computer processing Information (CPI)), water saturation (S_W), volume of shale (Vshale) and net pay were calculated by this program. Also, net porosity ($Ø_{Net}$) and net water saturation (SW_{Net}) were calculated which benefit in mapping of the future studies. The studied successions in each well were divided to many reservoir units independent on these information and related sedimentary microfacies. Because the core analysis not afford to this study by north oil company, the values less than 0.08% of porosity and the value more than 60% of water saturation were dependent in determine the cutoff cutoff as it used in north oil company. Although there are amount of hydrocarbon in carbonate beds within the lower part of the Fatha Formation known as transition beds especially in (T.5, T.10 and T.13), but the North oil company considers this occurrence of hydrocarbon with thin bed is worthless and the hydrocarbon reservoir began with what known main limestone include the Bajwan Formation and what underlying it in Kirkuk Field, and the Jeribe Formation and what underlying it in both Bai Hassan and Khabaz Fields, so this study depends on this viewpoint. The reservoir characterizations for each well arediscussed separately as follow:

KZ.29 Well

This well includes three reservoir units (Fig. 5 and Fig.6) and (Table 1) from top to bottom, they are: Unit 1 which is considered part of the Jeribe Formation and located at the top of this Formation at depth (2226 m) continued to (2232.2 m) and it has thickness (6.2 m). It consists of (1.4 m) thick of Dolomitized Lime Mudstone microfacies (DM) with intracrystalline porosity and (3.9m) thick of

ISSN: 1813 – 1662 (Print)
E-ISSN: 2415 – 1726 (On Line)

pelecypodal Packstone microfacies (PLP) with interparticles and intraparticles porosities. The highest average porosity ($Ø_{av}$) of this reservoir unit is (0.15) at depth (2229.8-2232.2 m) while the lowest value is (0.09) at depth (2226.8-2227.4 m), the highest value of average water saturation (SW_{av}) is (0.53) at depth (2226.8-2227.4 m) and the lowest value is (0.47) at depth (2228.3-228.9 m), the highest Vshale value is (2.15) at depth (2229.8-2232.2 m) while the lowest value is (0.61 m) at depth (2228.3-2228.9m). The net pay value of this unit is (3.6m), the net average porosity is (0.08), the net average water saturation is (0.28) and the total Volume of shale is (3.43); Unit 2 includes the lower part of the Jeribe formation, Anah Formation and the Anah/Azkand interfingering zone. It located at depth (2246.6-2268.8 m) and it has thickness (22.2 m) consists of (1.9 m) thick of Algal Wackestone microfacies of Jeribe Formation with channel and intraparticles porosities, (8m) thick of Benthic Foraminiferal Wackestone-Packstone microfacies of Anah Formation (BFWP) with intraparticles porosity, and (4.8 m) thick of Rotalid-Coraline Red Algae Packstone microfacies (RRP) of Anah/Azkand interfingering zone which has intraparticles, vuggy and fracture porosities. The highest average porosity ($Ø_{av}$) of this reservoir unit is (0.13) at depth (2264.9-2268.8 m) while the lowest value is (0.09) at depth (2246.6-2246.9 m), the highest value of average water saturation (SW_{av}) is (0.60) at depth (2247.8-2248.1 m) and the lowest value is (0.22) at depth (2261.9-2263.1 m), the highest Vshale value is (0.26) at depth (2264.9-2268.8 m) while the lowest value is (0.08) at depth (2246.6-2246.9m). The net pay value of this unit is (6.3m), the net average porosity is (0.03), the net average water saturation is (0.04) and the total Volume of shale is (0.88); Unit 3 which covered the Azkand Formation, and it expands from the top of this formation at depth (2281.4) to the depth (2330.9 m) and it has thickness (49.5 m) consists of (10.8 m) thick of Rotalid-Coraline Red Algae microfacies (RRP) covered the upper part of this unit, (8m) thick of Coraline Red Algae Packstone microfacies (RP) with vuggy, intraparticle, and fracture porosities represent the middle part of this unit, (7m) thick of Coral Boundstone microfacies (CB) with moldic and intraparticle porosities in the middle part of this unit. Also, part of Coraline Red Algae Packstone microfacies which has thickness (23.9m) with vuggy, intraparticle, and fracture porosities covered the lower part of reservoir unit 3. The highest average porosity ($Ø_{av}$) of this reservoir unit is (0.17) at depth (2298.8-2311.1 m) while the lowest value is (0.08) at depth (2291.9-2292.2 m), the highest value of water saturation (SW_{av}) is (0.48) at depth (2330-233.9 m) and the lowest value is (0.17) at depth (2298.8-2311.1 m), the highest Vshale value is (0.37) at depth (2323.4-2329.4) while the lowest value is (0.06) at depth (2296.1-2298.2m). The net pay value of this unit is (36 m), the net average porosity is (0.10), the net average water saturation is (0.20) and the total Volume of shale is (2.81). The hydrocarbon reservoir in this well covers the Jeribe Formation, Anah Formation Azkand Formation and the interfingering zone between the two latest formations. The total thickness of this reservoir is (105m) with net pay thickness (45.9m) and net average porosity (0.073) while the net saturation is (0.190), the volume of shale is (7.130)

Table 1. Reservoir characterization of Kz.29 Well.

	Depth (m)		Thick (m)	Reservoir Unit	Depth (m)		Thick (m)	Microfacies	Depth (m)		Thick (m)	Interval No.	Depth (m)		Thick (m)	Φ average	Sw average	VShale	Φ average Net	Sw average Net	Net Pay	VShale Unit
	Top	Bottom			Top	Bottom			Top	Bottom			Top	Bottom								
Jeribe	2226	2248.5	22.5	1	2226	2232.2	6.2	DM	2226	2228	2	1	2226.8	2227.4	0.6	0.0932	0.5371	0.665	0.0861	0.28415	3.6	3.4311
								PLP	2228	2232	4	1	2228.3	2228.9	0.6	0.1471	0.4788	0.6102				
												2	2229.8	2232.2	2.4	0.1551	0.4801	2.1559				
				2	2246.6	2268.8	22.2	AW	2246	2248.5	2.5	1	2246.6	2246.9	0.3	0.0986	0.4274	0.0876	0.0335	0.04965	6.3	0.8848
												2	2247.8	2248.1	0.3	0.113	0.6028	0.1396				
Anah	2248.5	2264	15.5					BFWP	2256	2264	8	1	2246.6	2246.9	0.3	0.0986	0.4274	0.0876				
												2	2259.5	2259.8	0.3	0.1004	0.3333	0.0879				
												3	2261.9	2263.1	1.2	0.1044	0.2279	0.1469				
Anah/ Azkand	2264	2281	17					RRP	2264	2269	5	1	2264.9	2268.8	3.9	0.1321	0.238	0.2644				
Azkand	2281	2341	60	3	2281.4	2330.9	49.5	RRP	2281	2292	11	1	2281.4	2284.4	3	0.1028	0.3077	0.0973	0.1001	0.2013	36	2.8146
												2	2288	2291.3	3.3	0.107	0.2964	0.3068				
												3	2291.9	2292.2	0.3	0.0852	0.3367	0.0756				
								RP	2292	2300	8	1	2296.1	2298.2	2.1	0.1391	0.2881	0.0655				
								CB	2300	2307	7	1	2298.8	2311.1	12.3	0.1773	0.1751	1.0579				
								RP	2307	2341	34	1	2311.7	2315.6	3.3	0.1093	0.3901	0.1007				
												2	2317.4	2322.2	4.8	0.1318	0.3453	0.2869				
												3	2323.4	2329.4	6	0.1245	0.3531	0.3718				
												4	2330	2330.9	0.9	0.1077	0.4813	0.0803				

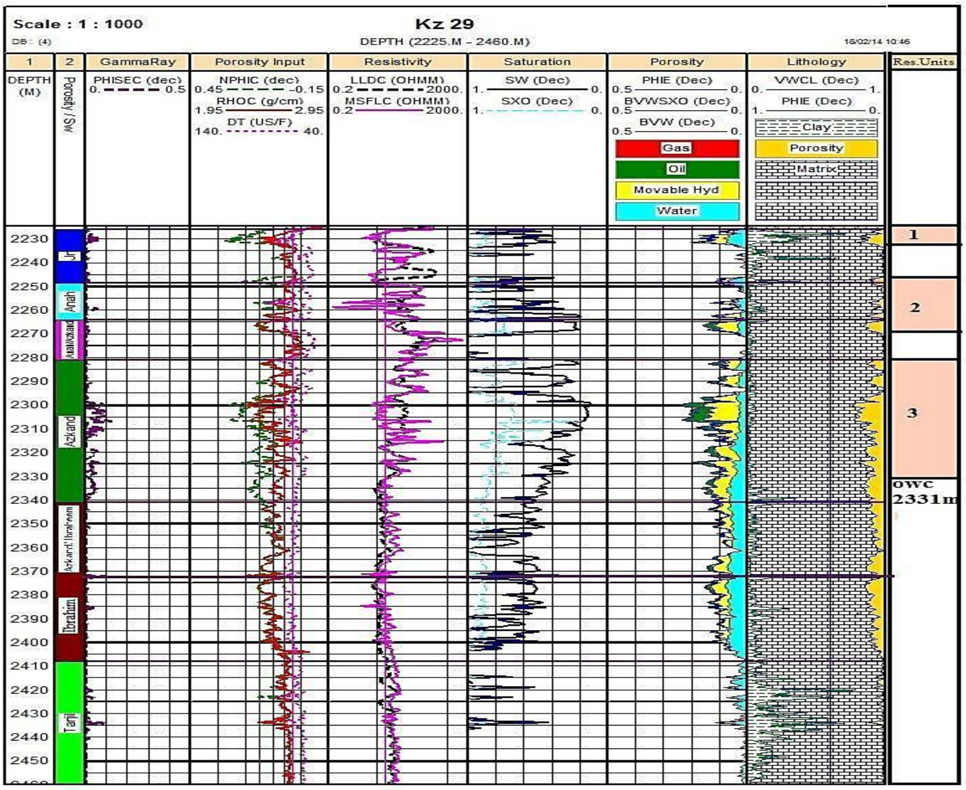

Figure 5 Reservoir units upon the well logs and reservoir characterization of KZ.29Well

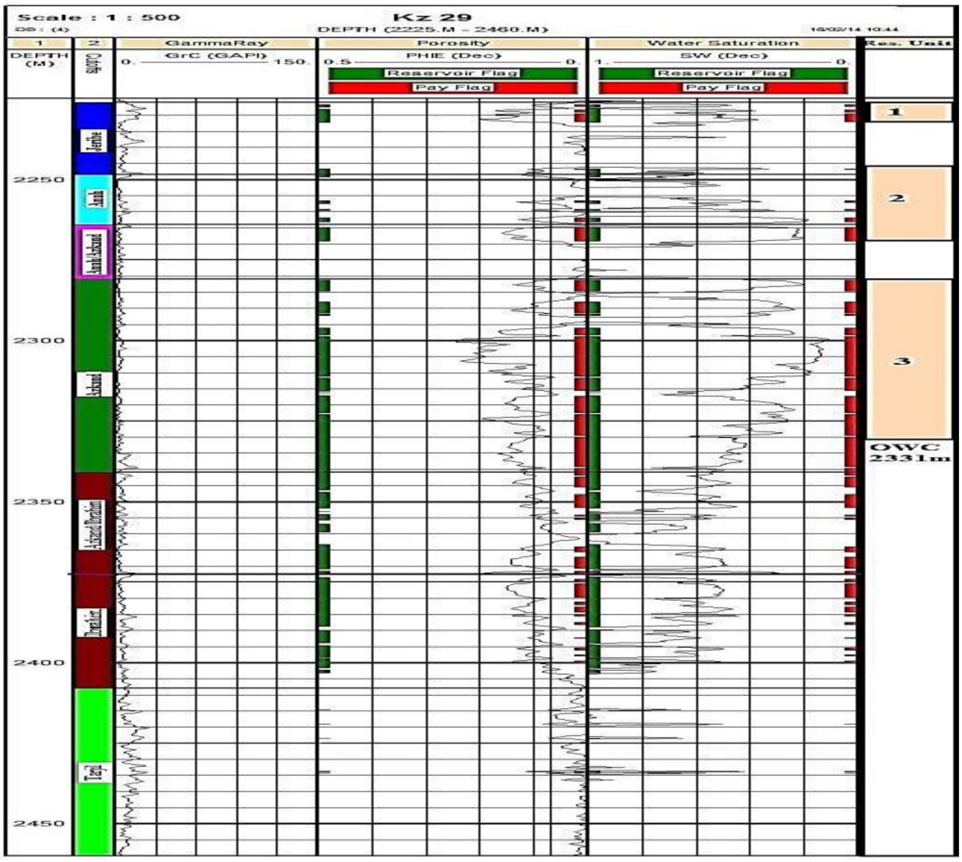

Figure 6 Reservoir units upon the cutoff of net porosity and net water saturation of KZ.29Well

KZ.23 Well

Three reservoir units were identified in this well dependent on well logs analysis and petrographic study (Fig. 7 and Fig.8) and (Table 2): Unit 1 which has (14.9 m) thick and it represent the upper and middle parts of the Jeribe Formation where it extended from the top of this Formation at depth (2169 m) and continued to (2183.9 m), it consist of (1.2 m) thick of Dolomitized Mudstone microfacies (DM) with intracrystalline porosity, (1.8 m) thick of pelecypod Packstone microfacies (PLP) with interparticles and intraparticles porosities and (1.5 m) thick of Benthic Foraminifera Wackestone microfacies (BFW) with intraparticles and vuggy porosities. The highest average porosity (Øav) of this reservoir unit is (0.13) at depth (2174.6-2175.8 m) while the lowest value is (0.08) at depth (2183.6-2183.9 m), the highest value of average water saturation (SW av) is (0.36) at depth (2174.6-2175.8 m) and the lowest value is (0.18) at depth(2179.1-2180.9 m), the highest Vshale value is (1.16) at depth (2182.1-2183.3 m) while the lowest value is (0.14 m) at depth (2183.6-2183.9 m). The net pay value of this unit is (4.5 m), the net average porosity is (0.03), the net average water saturation is (0.08) and the total Volume of shale is (2.54); Unit 2 covered the lower part of the Jeribe formation, Anah Formation and the Anah /Azkand interfingering zone, it located at depth (2187.8- 2216.3 m) and it has thickness (28.5 m) consists of (5.2 m) thick of Benthic Foraminifera Wackestone microfacies (BFW) with intraparticles and vuggy porosities, (6m) thick of Algal Wackestone microfacies with channel and intraparticles porosities where these two microfacies belong to the Jeribe Formation, (1.4 m) of Lithoclastic Grainstone microfacies (LG) of Anah Formation with intraparticles porosity, (3.3 m) thick of Benthic Foraminiferal Wackestone-Packstone microfacies (BFWP) of Anah Formation with intraparticles porosity, (2 m) thick of Rotalid-Coraline Red Algae Packstone microfacies (RRP) which has intraparticles, vuggy and fracture porosities,(3 m) thick of Wackestone-Packstone microfacies (WP) with vuggy porosity and (1.3 m) thick of Coral Boundstone microfacies (CB) with moldic and intraparticle porosities where the last three microfacies belong to Anah /Azkand interfingering zone, the highest average porosity (Øav) of this reservoir unit is (0.18) at depth (2187.8-2200.4 m) while the lowest value is (0.09) at depth (2204.6-2205.5 m), the highest value of average water saturation (SW av) is (0.30) at depth (2187.8-2200.4 m) and the lowest value is (0.22) at depth (2204.6-2205.5 m) the highest Vshale value is (2.36) at depth (2187.8-2200.4 m) while the lowest value is (0.02) at depth (2204.6-2205.5 m). The net pay value of this unit is (22.2), the net average porosity is (0.13), the net average water saturation is (0.21) and the total Volume of shale is (3.57); Unit 3covered the Azkand Formation in addition to most of Azkand Ibrahim interbedded zone, it expands from the top of Azkand Formation at depth (2218.4 m) and expanded to the middle part of interbedded zone between this Formation and Ibrahim Formation at depth (2319.8 m), it has thickness (101.4 m) consists of repeating of many types of microfacies and alternative each other where it consist of (15 m) thick of Rotalid-Coraline Red Algae microfacies (RRP) covered the upper part of this unit, (57 m) thick of Coraline Red Algae Packstone microfacies (RP) with vuggy, intraparticle, and fracture porosities represent the middle part of this unit, (9 m) thick of Coral Boundstone microfacies (CB) with moldic and intraparticle porosities, and (16.8 m) of *Globigerinoides* Wackestone - Packstone microfacies (GldWP) of Azkand / Ibrahim interbedded zone with intraparticles and vuggy porosities. The highest average porosity (Øav) of this reservoir unit is (0.20) at depth (2314.1-2315.6 m) while the lowest value is (0.11) at depth (2316.5-2319.8 m), the highest value of water saturation (SW av) is (0.53) at depth (2316.5-2319.8 m) and the lowest value is (0.14) at depth (2218.4-2260.4 m), the highest Vshale value is (9.40) at depth (2261-2313.2 m) while the lowest value is (0.29) at depth (2314.1-2315.6 m). The net pay value of this unit is (99 m), the net average porosity is (0.17), the net average water saturation is (0.23) and the total Volume of shale is (15.19). Table 2.Hydrocarbon reservoir covers the Jeribe Formation, Anah Formation and its interfingering zone with Azkand Formation, Azkand Formation and its interbedded with Ibrahim Formation. The total thickness of this reservoir is (151m) with net pay thickness (125.5 m) and net average porosity (0.12) while the net saturation is (0.18), the volume of shale is (7.130).

Table 2 Reservoir characterizations in KZ.23 Well

Formation	Depth (m) Top	Depth (m) Bottom	Thick (m)	Reservoir Unit	Depth (m) Top	Depth (m) Bottom	Thick (m)	Microfacies	Depth (m) Top	Depth (m) Bottom	Thick (m)	Interval No.	Depth (m) Top	Depth (m) Bottom	Thick (m)	Φ average	Sw average	VShale	Φ average Net	Sw average Net	Net Pay	VShale Unit
Jeribe	2169	2199	30	1	2169	2183.9	14.9	DM	2169	2175	6	1	2174.6	2175.8	1.2	0.13	0.36	0.65	0.03	0.08	4.5	2.54
								PLP	2175	2182	7	1	2179.1	2180.9	1.8	0.11	0.18	0.57				
								BFW	2182	2193	11	1	2182.1	2183.3	1.2	0.12	0.35	1.16				
												2	2183.6	2183.9	0.3	0.08	0.36	0.14				
Anah	2199	2210	11	2	2187.8	2216.3	28.5	AW	2193	2199	6	3	2187.8	2200.4	12.6	0.18	0.30	2.36	0.13	0.21	22.2	3.57
								LG	2199	2202	3											
								BFWP	2202	2210	8	1	2204.6	2205.5	0.9	0.09	0.22	0.02				
												2	2207.6	2216.3	8.7	0.17	0.23	1.18				
Anaha/Az	2210	2218	8					RRP	2210	2212	2											
								WP	2212	2215	3											
								CB	2215	2216	1											
Azkand	2218	2291	73	3	2218.4	2319.8	101.4	RRP	2218	2227	9	1	2218.4	2260.4	42	0.16	0.14	4.87	0.17	0.23	99	15..19
								RP	2227	2237	10											
								CB	2237	2246	9											
								RP	2246	2255	9											
								RRP	2255	2262	7											
								RP	2262	2291	29	1	2261.1	2313.2	52.2	0.19	0.29	9.40				
Azkand/Ib	2291	2327.5	36.5					GldWP	2291	2303	12											
								RP	2303	2311	9											
								GWP	2311	2321	10											
												1	2314.1	2315.6	1.5	0.2	0.47	0.29				
												2	2316.5	2319.8	3.3	0.11	0.53	0.61				

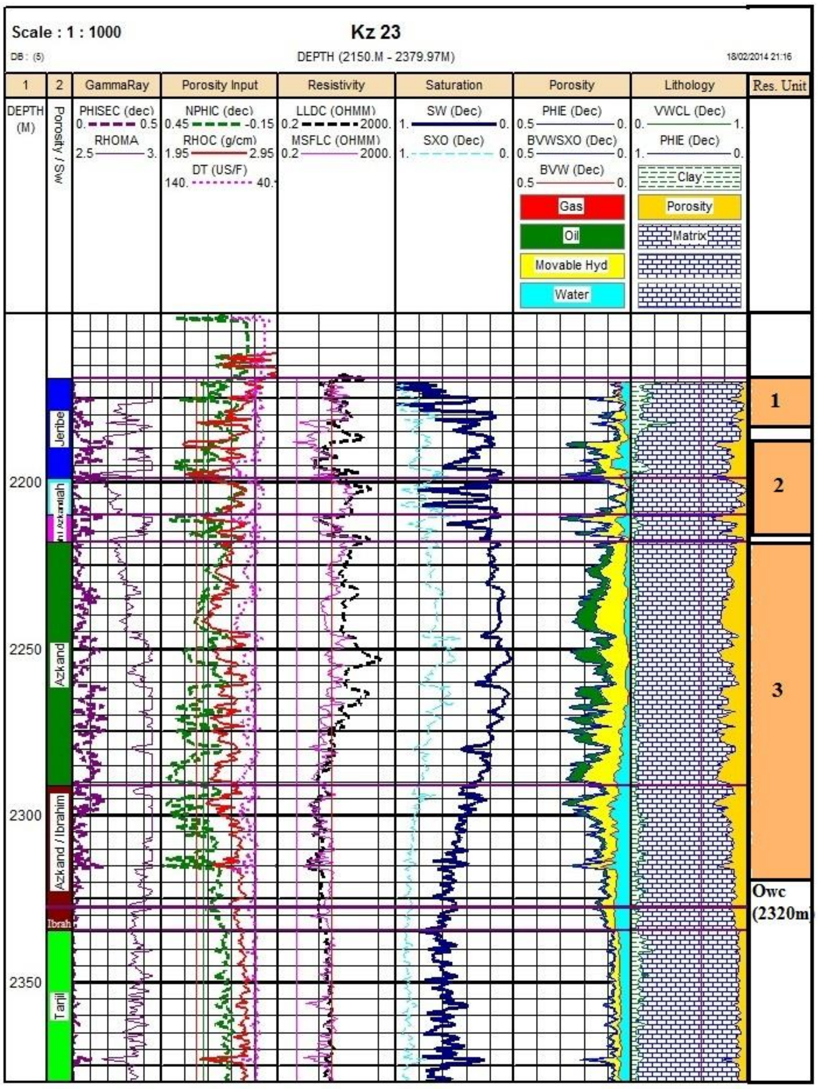

Figure 7 Reservoir units upon the well logs and reservoir characterization of KZ.23Well

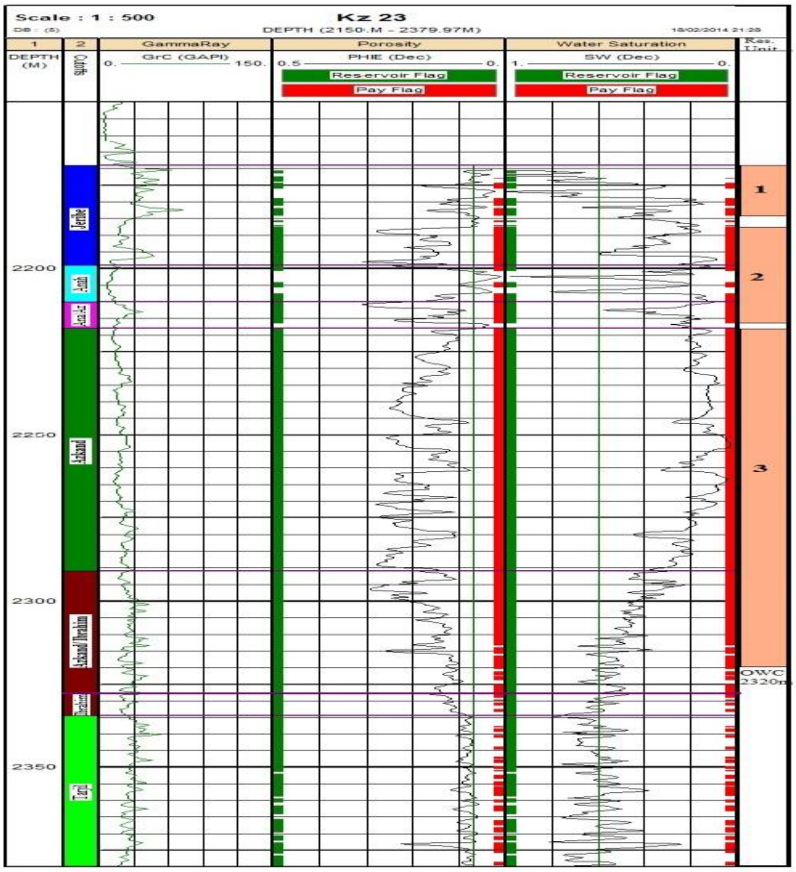

Figure 8 Reservoir units upon the cutoff of net porosity and net water saturation of KZ.23Well

K.218 Well

According to the analyzed data of different logs in this Well, four reservoir units were included: from top to bottom (Fig. 9 and Fig. 10) and (Table 3), these are: Unit 1 which has (19.8 m) thick and it covered the upper and middle parts of Bajwan Formation where it expanded from depth (408 m) to (428.2 m), the highest average porosity (Øav) of this reservoir unit is (0.21) at depth (415.9-422.2 m) while the lowest value is (0.8) at depth (408.4-408.7 m), the highest value of water saturation (SW av) is (0. 58) at depth (415- 415.3 m) and the lowest value is (0.29) at depth (408.4- 408.7 m), the highest Vshale value is (3.10) at depth (415.9-422.2 m) while the lowest value is (0.12) at depth (408.4- 408.7 m), The net pay value of this unit is (15 m), the net average porosity is (0.13), the net average water saturation is (0.25) and the total volume of shale is (8.61); Unit 2 covered the lower part of Bajwan Formation (lower part of Bajwan porous unit) and the Baba Formation entirely where it stretched from the depth (429.1- 465.7 m) with (36.2 m) thick. The average porosity (Øav) of this reservoir unit is (0.19), the value of the average water saturation (SW av) is (0. 12) and the Volume of shale value is (4.76), the net pay value of this unit is (36.6 m), the net average porosity is (0.19), the net average water saturation is (0.12) and the total Volume of shale is (4.76); Unit 3 represents the upper part of the Shurau Formation and it located at depth (468.1 m) to (475.3 m) and it has thickness (7.2 m), the average porosity (Øav) of this reservoir unit is (0.16), the value of the average water saturation (SW av) is (0. 14) and the Volume of shale value is (0.56). The net pay value of this unit is (7.2 m), the net average porosity is (0.16), the net average water saturation is (0.14) and the total Volume of shale is (0.56); Unit 4 has (65.7 m) thick and it includes the lower part of Shurau Formation, Whole Sheikh Allas Formation and the Sheikh Allas/Palani interbedded zone completely where it expanded from depth (477.4-543.1 m), the average porosity (Øav) of this reservoir unit is (0.21), the value of the average water saturation (SW av) is (0. 11) and the Volume of shale value is (9.33). The net pay value of this unit is (65.7 m), the net average porosity is (0.21), the net average water saturation is (0.11) and the total volume of shale is (9.33). Although the oil-water contact in this well was located at the depth (635 m) within the Jaddala Formation, but the microfacies and petrographic study shows that there are less porosity in the Palani and Jaddala Formations, and the end of hydrocarbons existence in the Sheikh Allas/Palani interbedded zone at the upper contact of the Palani Formation is regarded as the lowest oil. Also the well logs analysis indicated that the porosity is lower than (0.08) and the water saturation is larger than (0.6) under the top of the Palani Formation at depth (543 m) which considered as a cutoff by the North Oil Company (when there are no core analysis) therefore, the depth from the top of the Palani Formation and

ISSN: 1813 – 1662 (Print)
E-ISSN: 2415 – 1726 (On Line)

what below it is not taken in mind as part of this reservoir unit within K.218 Well in this study. The hydrocarbon reservoir in this well covers the Bajwan Formation, Baba Formation, Shurau Formation, Sheikh Allas Formation and its interbedded with Palani Formation. The total thickness of this reservoir is (136 m) with net pay thickness (124.5 m) and net average porosity (0.178) while the net saturation is (0.159), the shalinees is (5.82).

Table 3 Reservoir characterization of K.218 Well

Formation	Depth (m)		Thick (m)	Reservoir Unit	Depth (m)		Thick (m)	Interval No.	Depth (m)		Thick (m)	Φ average	Sw average	VShale	Φ average Net	Sw average Net	Net Pay	VShale Unit
	Top	Bottom			Top	Bottom			Top	Bottom								
Bajwan Dense	407	417	10	1	408.4	428.2	19.8	1	408.4	408.7	0.3	0.085	0.291	0.121	0.133	0.2523	15	8.61
								2	411.7	414.4	2.7	0.162	0.37	2.718				
								3	415	415.3	0.3	0.111	0.589	0.667				
Bajwan Porous	417	434	17					1	415.9	422.2	6.3	0.211	0.311	3				
								2	422.8	428.2	5.4	0.152	0.328	2.105				
Baba	434	466	32	2	429.1	465.7	36.6	1	429.1	465.7	36.6	0.198	0.127	4.767	0.198	0.127	36.6	4.77
Shurau	466	503	37	3	468.1	475.3	7.2	1	468.1	475.3	7.2	0.167	0.148	0.567	0.167	0.148	7.2	0.57
				4	477.4	543.1	65.7	1	477.4	543.1	65.7	0.217	0.117	9.332	0.217	0.117	65.7	9.33
Sheikh Allas	503	529	26															
Seikh Allas/ Palani	529	543	14															

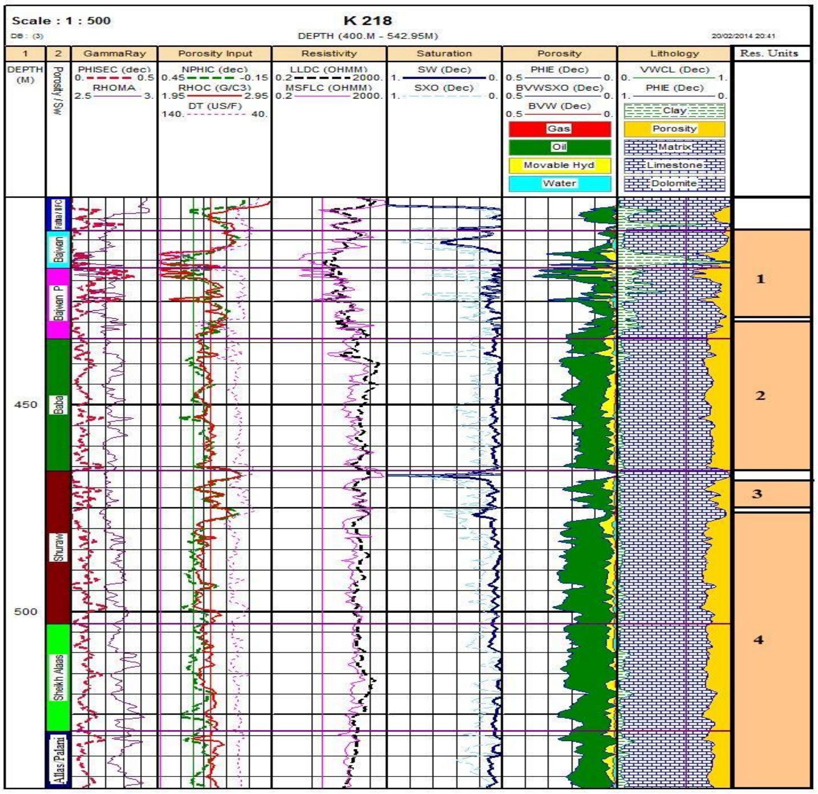

Figure 9 Reservoir units upon the well logs and reservoir characterization of K.218Well

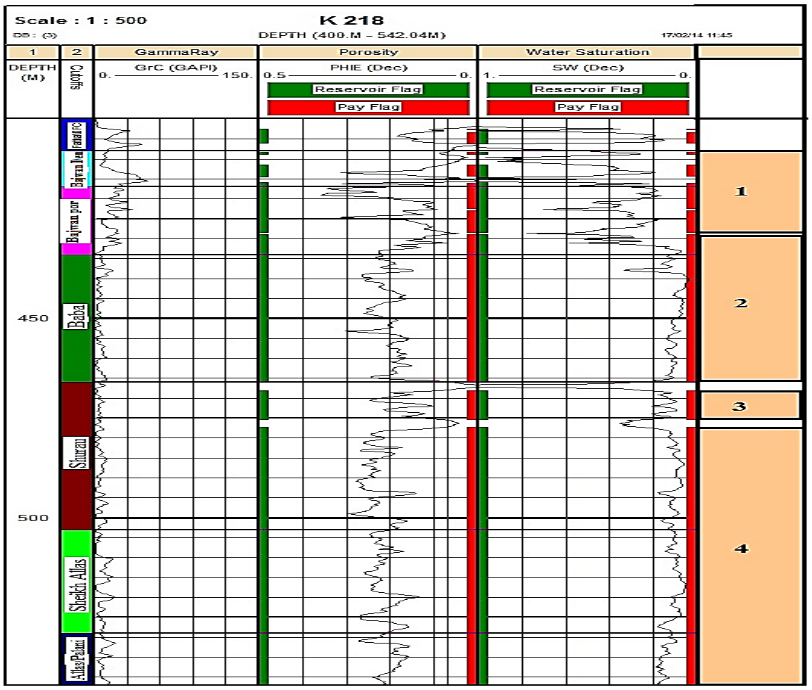

Figure 10 Reservoir units upon the cutoff of net porosity and net water saturation of K.218Well

BH.90 Well

Three reservoir units were identified in BH.90 Well of Kithka dome within Bai Hassan Field (Fig. 11) and (Table 4), these are: Unit 1 covered the Jeribe Formation entirely with thickness (14.7 m) where it located at depth (884.3 m) and continued to depth (899 m). It consists of (0.7 m) thick of Quartz Grains bearing Mudstone microfacies (QM) with vuggy porosity, (2 m) of Dolomitized Mudstone microfacies (DM) with intracrystalline porosity, (5 m) thick of pelecypodal Packstone microfacies (PLP) with interparticles and intraparticles porosities and (5 m) thick of Benthic Foraminifera Wackestone microfacies (BFW) with intraparticles and vuggy porosities and (2 m) thick of Algal Wackestone microfacies with channel and intraparticles porosities, the highest average porosity value (Øav) of this reservoir unit is (0.15) at depth (890.6-899 m) while the lowest value is (0.11) at depth (884.3-885.2 m), the highest value of water saturation (SW av) is (0.24) at depth (886.1-889.4 m) and the lowest value is (0.05) at depth (884.3-885.2 m), the highest Vshale value is (5.67) at depth (890.6-899 m) whereas the lowest value is (0.52) at depth(884.3-885.2 m). The net pay value of this unit is (12.6 m), the net average porosity is (0.12), the net average water saturation is (0.17) and the total Volume of shale is (7.80); Unit 2 covered the upper part of Bajwan Formation what known as Bajwan dense unit, it expanded from the depth (909.8 m) to (921.5m) with (11.7m) thick, it consists of (11.7 m) of Bioclastic Packstone microfacies (BsP) with intraparitcles and moldic porosities, the highest average porosity value (Øav) of this reservoir unit is (0.15) at depth (909.8-910.4 m) while the lowest value is (0.08) at depth (916.6-917 m), the highest value of water saturation (SW av) is (0.41) at depth (916.7-917 m) and the lowest value is (0.22) at depth (911-912.5 m), the highest Vshale value is (1.90) at depth (917.9-921.5 m) whereas the lowest value is (0.43) at depth(916.7-917 m), the net pay value of this unit is (14.1 m), the net average porosity is (0.08), the net average water saturation is (0.19) and the total Volume of shale is (5.89); Unit 3 covered the lower part of the Bajwan Formation (most of Bajwan porous unit) and the Baba Formation entirely, it has thickness (130.5 m) and located at depth (929-1059.5 m), it consist of (5 m) thick of Miliolid Packstone microfacies (MP) with intraparticle porosity, (5m) thick of Oolitic Grainstone microfacies (OG) with intraparticle porosity, (16m) thick of Coral Boundstone microfacies (CB) with intraparticles porosity, (8m) thick of Benthic Grainstone microfacies(BG) with intraparicles and moldic porosities, (40 m) thick of Coralline Red alagae-Nummulites Packstone (RNP) with moldic, vuggy and intraparticles porosities and (56 m) thick of Bioclastic Wackstone microfacies (BsW) with intraparticle where the first microfacies belong to the Bajwan Formation while others belong to the Baba Formation, the highest average porosity value (Øav) of this reservoir unit is (0.15) at depth (938-1059.5 m) while the lowest value is (0.12) at depth (932.3-933.8 m), the highest value of water saturation (SW av) is (0.12) at depth (929-930.8 m) and the lowest value is (0.09) at depth (938-1059.5 m), the highest Vshale value is (7.02) at depth (938-1059.5 m) whereas the lowest value is (0.12) at depth (934.1-936.8 m). The net pay value of this unit is (127.5m), the net average porosity is (0.15), the net average water saturation is (0.09) and the total

Volume of shale is (23.13).The oil-water contact (OWC) is not specified in the current study and the end of hydrocarbons existence in Baba reservoir near the contact between the Palani Formation at and Baba Formation in BH.90Well is regarded as the lowest oil. The hydrocarbon reservoir in this well covers the Jeribe Formation, Bajwan Formation and Baba Formation. The total thickness of this reservoir is (178 m) with net pay thickness (154.2 m) and net average porosity (0.121) while the net saturation is (0.156), the volume of shale is (36.837).

Table 4 Reservoir characterization of BH.90 Well

Formation	Depth (m)		Thick (m)	Reservoir Unit	Depth (m)		Thick (m)	Microfacies	Depth (m)		Thick (m)	Interval No.	Depth (m)		Thick (m)	Φ average	Sw average	VShale	Φ average Net	Sw average Net	Net Pay	VShale Unit
	Top	Bottom			Top	Bottom			Top	Bottom			Top	Bottom								
Jeribe	884	899	15	1	884.3	899	14.7	QM	884	885	1	1	884.3	885.2	0.9	0.113	0.054	0.528	0.128	0.171	12.6	7.808
								DM	885	887	2	1	886.1	889.4	3.3	0.143	0.248	1.604				
								PLP	887	892	5	1	890.6	899	8.4	0.155	0.195	5.676				
								BFW	892	897	5											
								AW	897	899	2											
Bajwan Dense	899	923	24	2	909.8	921.5	11.7	BsP	905	921	16	1	909.8	910.4	0.6	0.152	0.315	0.814	0.084	0.199	14.1	5.899
												2	911	912.5	1.5	0.13	0.226	0.935				
												3	913.1	914	0.9	0.134	0.273	0.623				
												4	914.9	916.1	1.2	0.114	0.358	1.192				
												5	916.7	917	0.3	0.087	0.414	0.433				
												6	917.9	921.5	3.6	0.115	0.277	1.901				
Bajwan Porous	923	934	11	3	929	1059.5	130.5	MP	921	934	13	1	929	930.8	1.8	0.13	0.122	0.259	0.151	0.098	127.5	23.13
												2	932.3	933.8	1.5	0.128	0.106	0.139				
Baba	934	1059	125					OG	934	939	5	1	934.1	936.8	2.7	0.146	0.12	0.124				
								CB	939	955	16	1	938	1059.5	121.5	0.153	0.091	7.026				
								BG	955	963	8											
								RNP	963	1003	40											
								BsW	1003	1059	56											

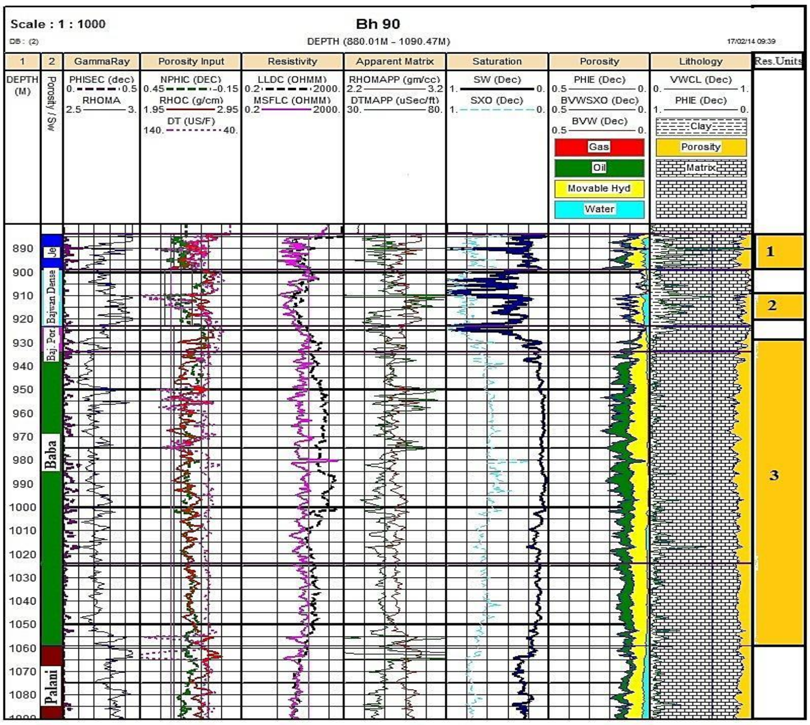

Figure 11 Reservoir units upon the well logs and reservoir characterization in BH.90 Well

Conclusions

1. According to the petrographic study, microfacies analysis, well logs analysis, and petrophysical properties, four reservoir units were concluded in Kirkuk Field. The first unit include the Bajwan Formation, the second unit include the lower part of Bajwan Formation and whole Baba Formation, the third reservoir unit include the upper part of the Shurau Formation, and the fourth one include the middle and lower part of the Shurau Formation and the Sheikh Allas Formation completely.
2. In Bai Hassan Field, three reservoir units were recognized: unit 1 include the Jeribe Formation, unit 2 includes the middle part of the Bajwan Formation, and unit 3 includes the Baba Formation.

ISSN: 1813 – 1662 (Print)
E-ISSN: 2415 – 1726 (On Line)

3. The end of hydrocarbon existence in Baba reservoir and Sheikh Allas reservoir is near the upper contact of the Palani Formation within both Bai Hassan and Kirkuk respectively, It is regarded as the lowest oil which considered the end of the last unit in these fields.

4. In Khabaz Field, three reservoir units were recognized: unit I include the Jeribe Formation, unit 2 include the Anah Formation and unit three include the Azkand Formation. The fourth unit was bounded by the oil-water contact.

5. Shallow marine carbonates of Kirkuk, Bai Hassan and Khabaz oilfields that deposited during the Upper Palaeogene-Lower Neogene were affected by subaerial exposure and meteoric diagenesis, in which meteoric dissolution resulted in the enhancement of secondary porosity, in addition to occluding primary porosity during stabilization of metastable minerals.

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Tikrit Journal of Pure Science 21 (3) 2016 *ISSN: 1813 – 1662 (Print)*
E-ISSN: 2415 – 1726 (On Line)

الخواص المكمنية لتتابعات اعلى الباليوجين – اسفل النيوجين في حقول كركوك وباي حسن وخباز النفطية / شمال العراق

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الملخص

تم تقسيم تتابعات اعلى الباليوجين–اسفل النيوجين في ابار مختارة من حقول كركوك وباي حسن وخباز النفطية الى عدة وحدات مكمنية استنادا الى المعلومات المستقاة من الوصف البتروغرافي وتحاليل المجسات ووالسحنات الدقيقة المرتبطة معها . يضم المكمن الهيدروكربوني في حقل خباز ثلاث وحدات مكمنية تشمل تكوين الجريبي، وتكوين عانة وتداخله مع تكوين ازقند، وتكوين ازقند، يبلغ السمك الكلي لهذا المكمن (128 م) وسمك العطاء الصافي (85.7 م) وصافي معدل المسامية (0.096) وصافي التشبع المائي (0.185) وان حجم السجيل هو (7.130) . يتمثل المكمن الهيدروكربوني في حقل باي حسن بثلاث وحدات مكمنية ايضا تضم كلا من تكويني باجوان وبابا، وان السمك الكلي له هو (178 م) وسمك العطاء الصافي (154.2 م) ومعدل المسامية الصافي (0.121) بينما يبلغ صافي التشبع المائي (0.156) وحجم السجيل (36.837) . يتكون المكمن الهيدروكربوني في حقل كركوك من اربع وحدات مكمنية غطت تكوينات باجوان وبابا وشوراو وشيخ علاس، إذ يبلغ السمك الكلي لهذا المكمن (136 م) وسمك العطاء الصافي (124.5 م) ويبلغ معدل المسامفية الصافي (0.178) ويبلغ صافي التشبع المائي (0.159) وحجم السجيل هو (5.82).

هناك عدة انواع من المسامية قد صاحبت هذه المكامن الهيدروكربونية والتي تم تشخيصها من الدراسة البتروغرافية مثل المسامية ما بين الحبيبات، والمسامية ضمن الحبيبات، والمسامية ما بين البلورات، ومسامية التكسرات، ومسامية القنوات، ومسامية القوالب، مسامية الفجوات، ومسامية التكهفات. ويعزى نشوء هذه الأنواع من المسامية الى عمليات الدلمتة والتكسرات والإذابة.