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Research Paper

Formation Evaluation of a Sandstone Reservoir in Kunmi-1 Well, Wildcat Field (Offshore)

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ABSTRACT
A section (4711.00 – 5401.00 ftTVDSS) of Kunmi-1 Well (offshore, Wildcat Field) was evaluated to access the impact of clay beds on the reservoir properties of the formation and provide an interpretation of the logged section with respect to lithology, porosity, saturation, net reservoir and pay thicknesses as well as delineating fluid contacts.
Data from wireline logs was used to delineate lithology and to estimate porosity and other parameters before correction. Pressure–depth plot reveals contact between the well fluids interpreted from fluid gradients. Data from mud logs indicates hydrocarbon shows and intervals, whereas core analysis data indicates core porosity and permeability. The total data extent is 690.00 ft with an increment of 0.50 ft.
The lithology in the reservoir consists mainly of sandstone with significant clay intervals. The value obtained for Vclay is 0.20 for clean sand intervals in the formation. An intermediate value of 0.18 was used as porosity cut-off, above which any interval is assumed not porous. The saturation cut-off values adopted range from 0.50 to 0.60. Zones 2, 3, 4, 6, 8, and 10 form the net reservoir with a total of 222.00 ft. The Net-to-Gross ratio is 0.32 and the average porosity and formation water saturation are 0.27 and 0.47, respectively. Conversely, the net pay, about 164.00 ft thick, comprises Zones 2, 4, 6, and 8 with average porosity and formation water saturation of 0.29 and 0.27, respectively.
The hydrocarbon fluid in the well is oil, as indicated by its gradient. However, the oils in the reservoir seem not to be in communication. The free water level is found at 5280 ftTVDSS. This depth represents the base of the oil column in Kunmi-1 Well.
KEYWORDS: *net-to-gross ratio, reservoir, wireline logs, communication.*

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I. INTRODUCTION

The quest to understand the nature and petrophysical properties of hydrocarbon reservoirs in order to predict their behaviour for optimum yield of oil and gas, has given reasons for their evaluation. Formation evaluation refers to the process of using borehole measurements to evaluate the characteristics of subsurface formations [1]. Shale/clay beds are not good reservoir rocks because they lack both effective porosity and permeability [3]. Consequently, the occurrence of clay beds within a formation tends to reduce its quality as a reservoir.

Formation evaluation of a sandstone reservoir interval extending from 4800 ft to 5490 ft in Kunmi-1 Well (offshore, Wildcat Field) was undertaken to determine the impact of clay beds on reservoir properties of the formation. The evaluation is aimed at providing quantitative evaluation of clay volume, porosity, saturation, net reservoir and pay thicknesses, and to delineate hydrocarbon bearing zones and define hydrocarbon limits and/or contacts.

II. GEOLOGICAL SETTING

The discovery well (Kunmi-1) penetrates a reservoir formation that is dominated by sandstone. The interval under consideration in this study extends from 4800 ft (Top) to 5490 ft (Base). Total depth of the well is 6718 ft. The clastic reservoir consists of sandstone, clayey sandstone and claystone. Reservoir properties are highest in sandstone and lowest in clayey sandstone. Claystone lacks reservoir characteristics; hence it is interpreted as a non-reservoir.

III. METHODS

The data used for this study was sourced from wireline logs (Gamma Ray, Density, Neutron, Sonic and Resistivity), Repeat Formation Test (RFT), mud logs and core. Gamma Ray log was used together with Density log to delineate lithology. Sonic log indicated matrix porosity and resistivity logs indicated presence of hydrocarbon where there was a separation between deep and shallow resistivities [2]. The RFT data was used to construct pressure-depth plot. The plot reveals probable location of fluid contacts in Kunmi-1 well. Data from mud logs reveal three intervals with hydrocarbon shows *viz*: (1) 4901 to 4956 ftTVDSS (2) 5111 to 5146 ftTVDSS (3) 5221 to 5253 ftTVDSS. The data from mud logs also show that the reservoir is dominated by light hydrocarbon components comprising C1, C2, C3, IC4, and NC4. Salinity measurement of the well was found to be less than 10,000 ppm indicating relatively fresh water. The reported downhole temperature measured is 206^{o}F. The Kelly Bushing Elevation is 89.0 ft.

Core porosity and permeability data were obtained from special core analysis of a nearby well. The data indicate that the following parameters are appropriate:

i. Archie constant (a) = 1.0;
ii. Cementation constant (m) = 1.8; and
iii. Saturation exponent (n) = 1.8.

IV. RESULTS

A. Parameters

The Gamma Ray value for the matrix was read directly from a Gamma Ray-Density Crossplot (Figure 1). Standard Density, Neutron, and Sonic values for sandstone were used for the matrix. Conversely, the Gamma Ray, Density, Neutron, and Sonic values for wet clay were read off from the Gamma Ray-Density, Gamma Ray-Neutron, and Gamma Ray-Sonic Crossplots (Figure 2) using Zone 4 (CLYST B) as a representative clay interval (Table 1). From mudlogger’s description, there is no visible cement. As a result, compaction factor was assumed to be 1.0. For pore fluid properties, standard Density, Neutron, and Sonic values were used.

The Archie constant (a), cementation (m), and saturation (n) parameters were obtained from special core analysis data from a nearby well. For Rw, a value corresponding to the downhole temperature (206 ^{o}F) was read off from chart showing the relationship between resistivity, temperature and salinity (Appendix 1). This value was used as a test parameter on the Pickett plot (Figure 3) to obtain a corrected Rw estimate of 0.65. On the other hand, Rclay was read off from resistivity log using the representative clay interval (CLYST B). The average Rclay value for the Zone is 5.8 (see Appendix 1).

B. Volume of Clay (Vclay)

Gamma Ray log reveals the degree of shaliness of a formation [2]. The Vclay was estimated from Gamma Ray log on the results plot using Zone 2 (SAND A) as the representative clean sand interval. The value obtained is 0.20. This value provides a cut-off such that any interval above this value would be regarded as a non-reservoir (Table 2).

C. Porosity

A graph of Core Porosity *versus* Horizontal Permeability (Figure 4) provided porosity cut-off for the reservoir. These cut-offs range from 0.05 to 0.24 with equivalent permeability range of 0.10 to 1.00 mD. The porosity values of 0.05 and 0.18 at 0.10 mD indicate the best and intermediate cases, respectively. On the other hand, porosity value of 0.24 indicates the worst case at 1.00 mD. Thus, the intermediate value of 0.18 was used as the porosity cut-off above which any interval was assumed not porous.

D. Water Saturation

The graph of formation water saturation *versus* porosity (Figure 5) was used to obtain saturation cut-off values. The plot indicates a maximum saturation value of 0.8. However, the saturation cut-off values used range from 0.50 to 0.60.

E. Net Reservoir and Pay Cut-offs

The net reservoir and net pay properties were automatically calculated in the zone averages sheet using the aforementioned cut-off conditions. Consequently, Zones 1, 5, 7, 9 and 11 are cut off as impermeable zones (see Table 2). In the same vein, the assumed conditions defined also cut off Zones 1, 3, 5, 7, 9, 10, and 11 from the net pay.

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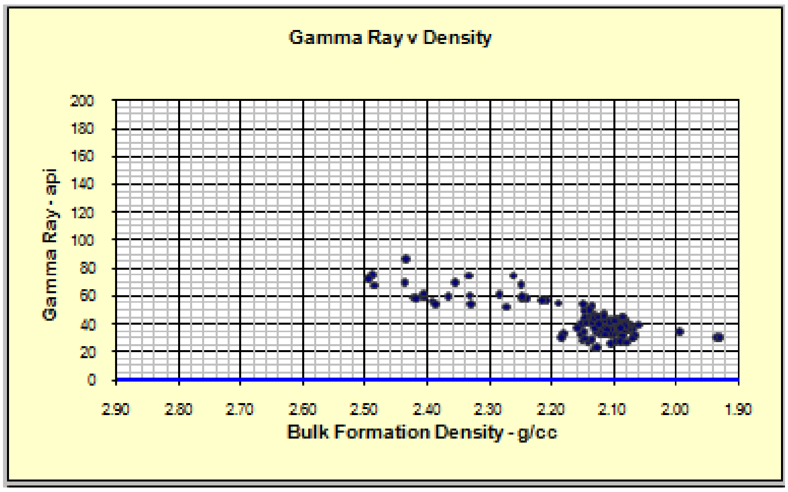

Figure 1. Gamma Ray-Density Crossplot showing GR reading for matrix as represented by clean sand interval in the Formation (Zone 2, SAND A).

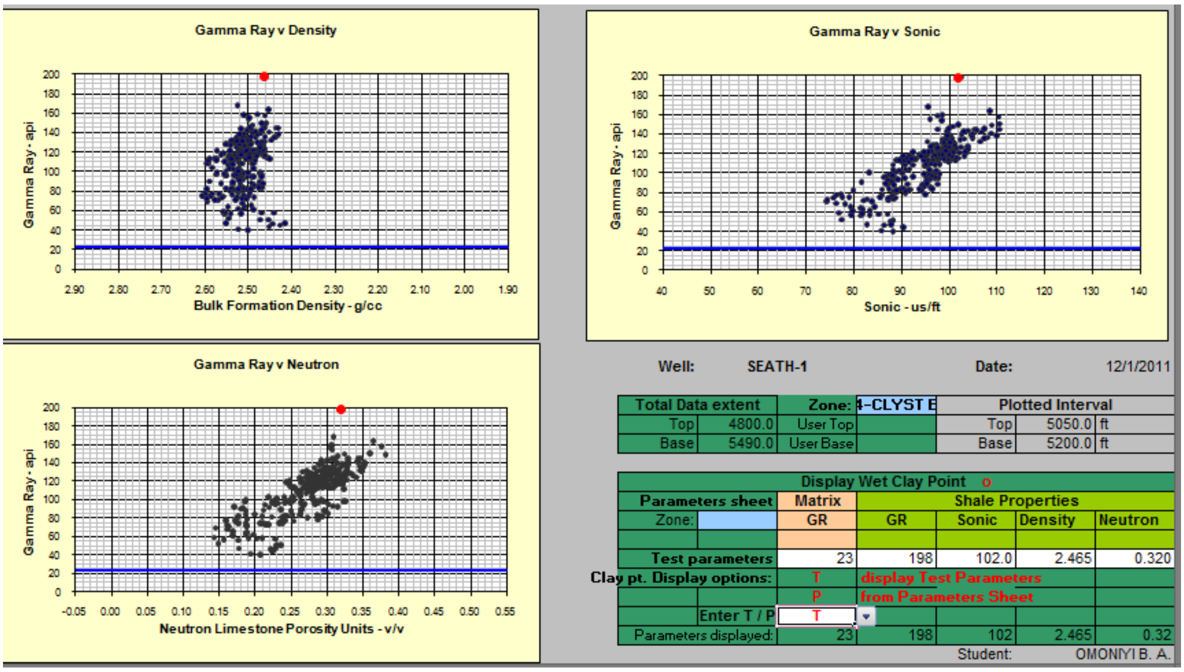

Figure 2. Gamma Ray-Density, Gamma Ray-Neutron, and Gamma Ray-Sonic Crossplots. Red point indicates wet clay point of a representative clay interval (Zone 4, CLYST B).

Table 1. Parameters of main zones delineated in the section evaluated in Kunmi-1 Well.

Zone Selection			Matrix Properties				Shale/Wet Clay Properties					Pore Fluid Properties		
Zone Name	Top	Base	Gamma Ray	Density	Neutron	Sonic	Gamma Ray	Density	Neutron	Sonic	Compaction Factor	Density	Neutron	Sonic
	ft	ft	api	g/cc	v/v	µs/ft	api	g/cc	v/v	µs/ft		g/cc	v/v	µs/ft
1. CLYST A	4800.0	4830.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
2. SAND A	4830.0	4908.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
3. CLY-SAND	4908.0	5050.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
4. CLYST B	5050.0	5200.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
5. SAND B	5200.0	5240.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
6. CLYST C	5240.0	5310.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
7. SAND C	5310.0	5380.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
8. CLYST D	5380.0	5415.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
9. SAND D	5415.0	5440.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189
10.CLYST E	5440.0	5440.0	23	2.65	-0.02	55.5	198	2.465	0.320	102.0	1	1.0	1.0	189

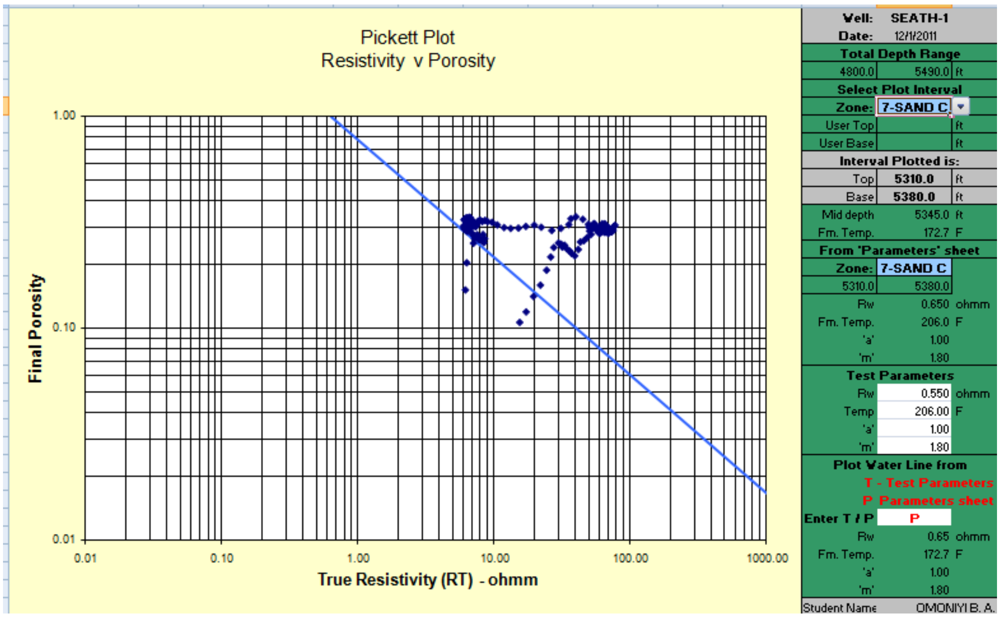

Figure 3. Pickett plot showing water line (Zone 7, SAND C).

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Table 2. Average properties for selected zones.

Zone Selection			Cut-off Selection				Net Reservoir				Net Pay				
Zone Name	Top	Base	Vclay	Porosity	Sw	Gross	Thickness	N/G	Porosity	Sw	Thickness	Porosity	Sw	EPC	EHC
1. CLYST A	4800.0	4830.0	0.20	0.18	0.60	30.0	0.0	0.000	No res	No res	0.0	No pay	No pay	0.000	0.000
2. SAND A	4830.0	4908.0	0.20	0.18	0.60	78.0	67.0	0.859	0.320	0.169	67.0	0.320	0.169	21.422	17.797
3. CLY-SAND	4908.0	5000.0	0.20	0.18	0.60	92.0	5.5	0.060	0.198	0.734	0.0	No pay	No pay	0.000	0.000
4. SAND (+OIL)	5000.0	5050.0	0.20	0.18	0.60	50.0	40.5	0.810	0.304	0.235	40.5	0.304	0.235	12.322	9.429
5. CLYST B	5050.0	5200.0	0.20	0.18	0.60	150.0	0.0	0.000	No res	No res	0.0	No pay	No pay	0.000	0.000
6. SAND B	5200.0	5240.0	0.20	0.18	0.60	40.0	23.5	0.588	0.250	0.366	23.5	0.250	0.366	5.886	3.730
7. CLYST C	5240.0	5310.0	0.20	0.18	0.60	70.0	0.0	0.000	No res	No res	0.0	No pay	No pay	0.000	0.000
8. SAND C	5310.0	5380.0	0.20	0.18	0.60	70.0	67.0	0.957	0.296	0.607	33.0	0.288	0.312	9.491	6.526
9. CLYST D	5380.0	5415.0	0.20	0.18	0.60	35.0	0.0	0.000	No res	No res	0.0	No pay	No pay	0.000	0.000
10. SAND D	5415.0	5440.0	0.20	0.18	0.50	25.0	18.5	0.740	0.265	0.715	0.0	No pay	No pay	0.000	0.000
11. CLYST E	5440.0	5490.0	0.20	0.18	0.50	50.0	0.0	0.000	No res	No res	0.0	No pay	No pay	0.000	0.000

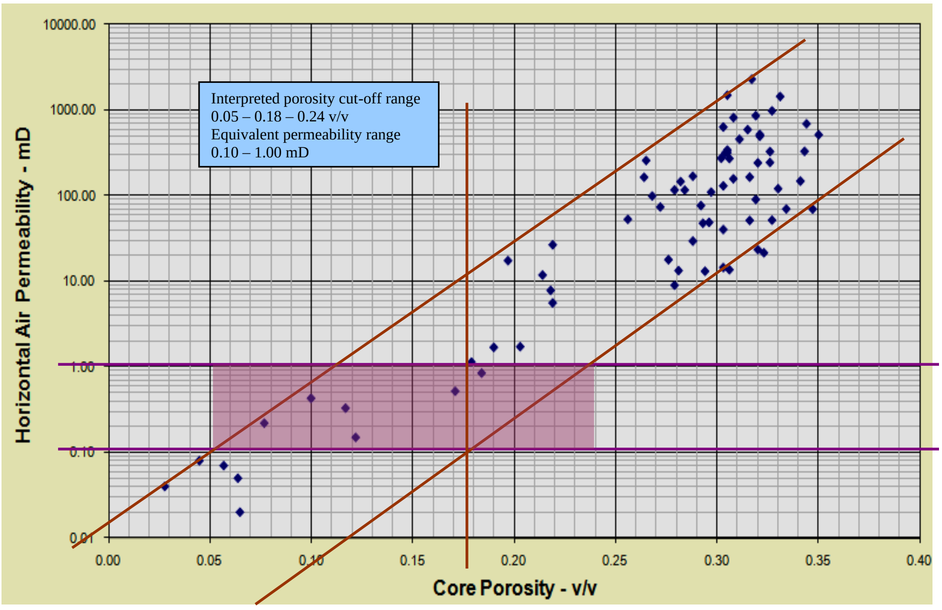

Figure 4. A graph of core porosity *versus* horizontal permeability showing porosity and permeability cut-offs used in this study.

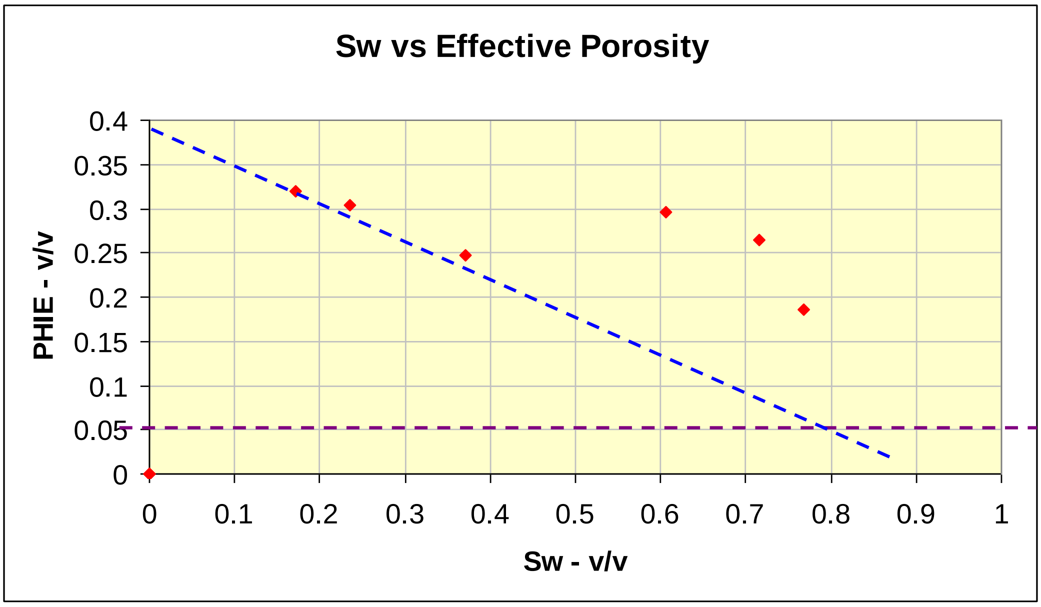

Figure 5. A graph of formation water saturation *versus* effective porosity showing minimum porosity cut-off for the present study.

V. DISCUSSION

A. Lithology

The lithology in the reservoir consists mainly of sandstone. However, it is associated with thick clay intervals (Figure 6). The clay beds occur as discrete beds in Zones 1, 4, 6, 8, and 10. In Zone 3, however, clay bed probably occurs as clayey sand (see Table 1).

B. Zonation

Ten zones were delineated from Kunmi-1 Well within the interval evaluated (4711-5401 ftTVDSS). However, these zones were increased to 11 (see Table 2) to ease interpretation.

C. Reservoir Properties

Zones 2, 3, 4, 6, 8, and 10 form the net reservoir with a total thickness of 222.00 ft within a gross thickness of 690.00 ft (see Figure 6 and Table 2). The Net-to-Gross ratio is 0.32. The average porosity for the net reservoir is 0.27, and the average formation water saturation is 0.47. However, only Zones 2, 4, 6, and 8 form the net pay with a total thickness of 164.00 ft. The average porosity and formation water saturation for the net pay were calculated to be 0.29 and 0.27, respectively. The EPC and EHC thicknesses are 49.12 ft and 37.48 ft, respectively.

D. Fluid and Fluid Contacts

The Pressure–Depth plot (Figure 7) constructed using RFT data reveals two fluid types in the reservoir – one is hydrocarbon and the other is not. On the basis of calculated gradients from fluid densities (Appendix 2), the hydrocarbon fluid was interpreted to be oil, whereas the non-hydrocarbon fluid was interpreted to be fresh water.

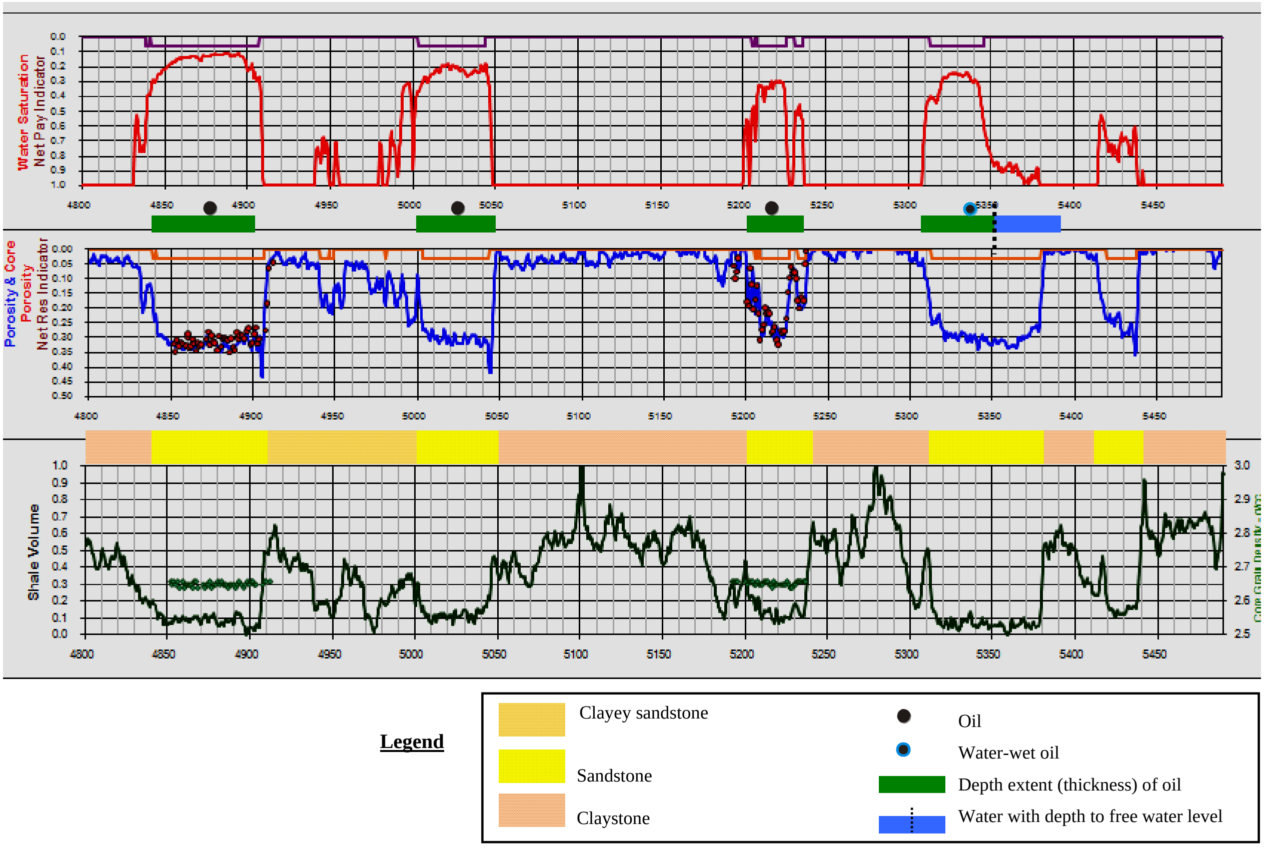

Figure 6. A summary of the reservoir properties showing zone boundaries, lithology, hydrocarbon shows, depth of hydrocarbon limits and contacts in Kunmi-1. Oil-water contact is estimated to occur at 5354 ftMD.

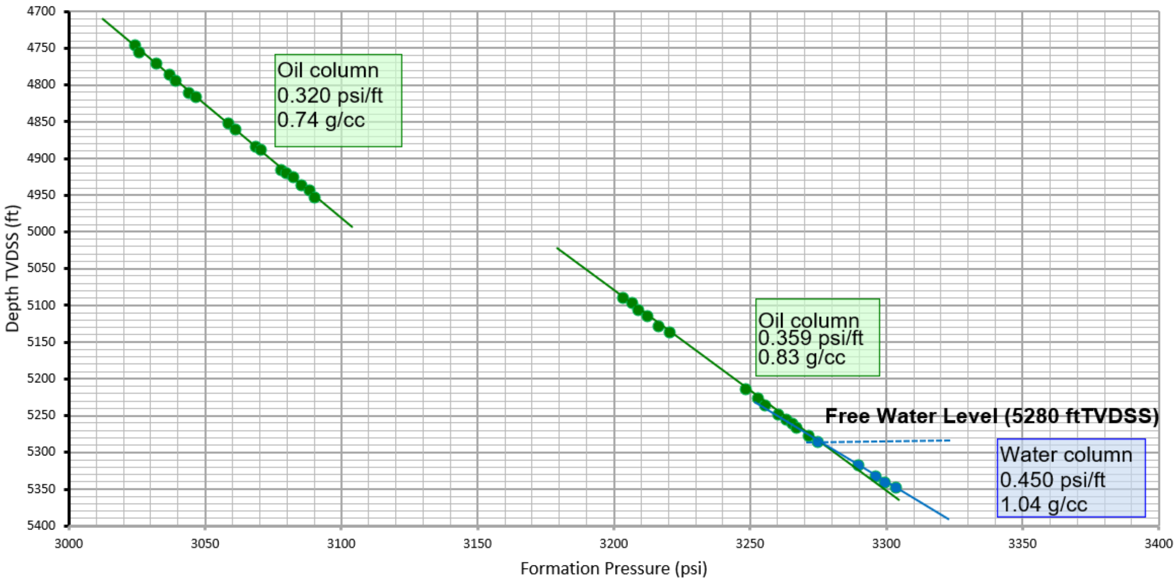

Figure 7. Pressure–depth plot for the interval evaluated in Kunmi-1. In contrast to oil-water contact read from wireline logs, the pressure-depth plot indicates a free water level that occurs at 5280 ftTVDSS in the well evaluated.

However, the oils in the well seem not to be in communication and the free water level is probably at 5280 ftTVDSS (see Figure 7). The free water level occurs below the oil-water contact. The difference in the depths could be caused by the effects of threshold capillary, which supports water above the free water level

(Andrew Stocks, *personal communication*, 2011). This further suggests that the reservoir quality has been reduced due to the presence of clay in the formation. The base of the oil column is probably at 5280 ftTVDSS.

VI. CONCLUSION

The findings in this study show that there is no gas in the hydrocarbon column in Kunmi-1 Well. The clay beds, as revealed by Pickett plot, consist mainly of dispersed and laminated clay. The clay is responsible for reducing the reservoir quality of the formation by reducing its net pay. The free water level is found to occur at 5280 ftTVDSS and this depth marks the base of oil column in the reservoir.

The interval extending from 4751 to 4821 ftTVDSS is not included in the mudlog oil show intervals. The formation evaluation of this interval indicates the presence of oil. Therefore, it is suggested that this interval be further investigated to reduce the key uncertainties that may arise from the cut-offs used to define the net pay and other sensitive parameters.

ACKNOWLEDGMENT

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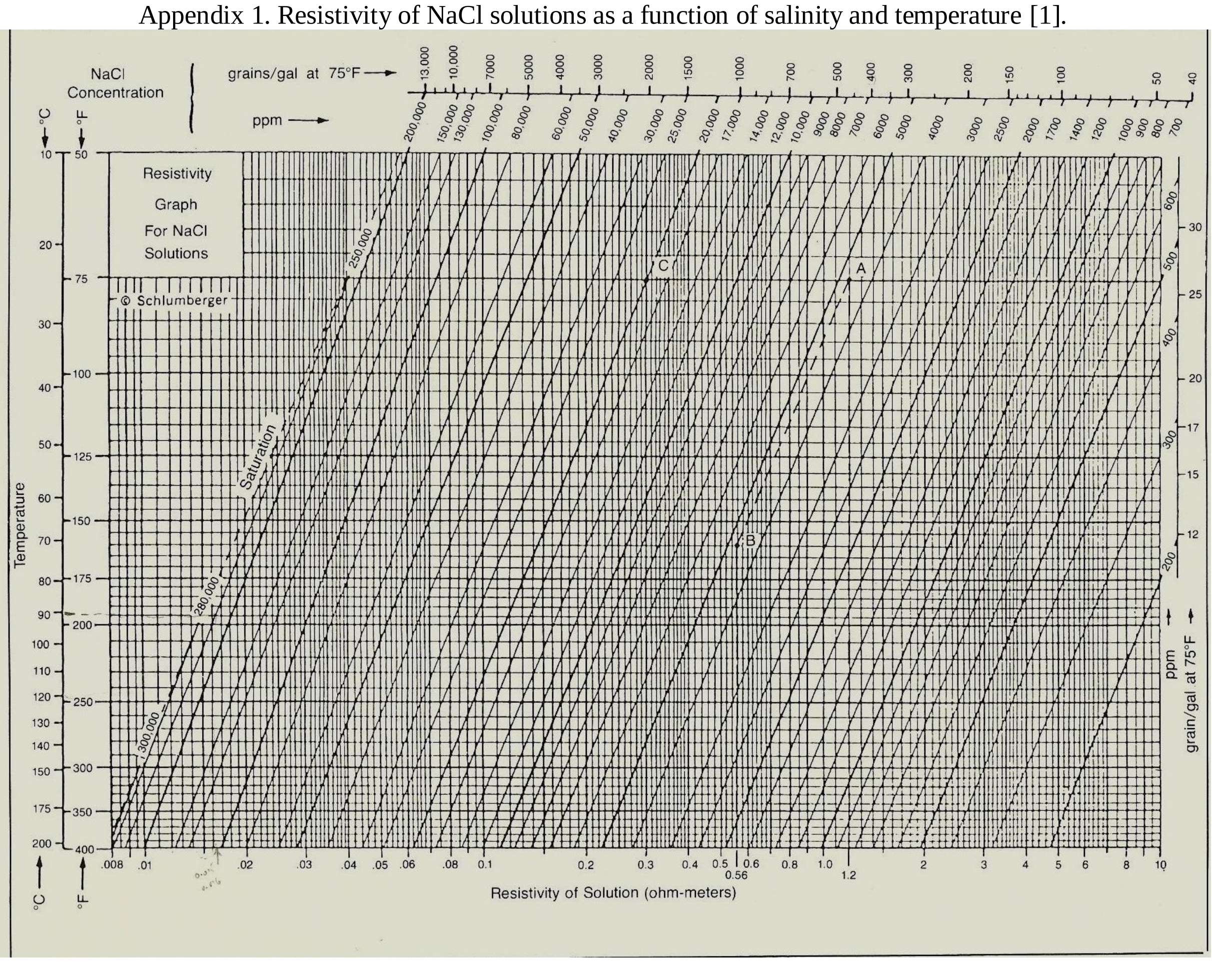
[3] Stocks, A. E., 2010. Basics of Petrophysics, Log Interpretation and Formation Evaluation: United Kingdom, University of Manchester, Lecture materials, 132 pp.

Appendix 1. Resistivity of NaCl solutions as a function of salinity and temperature [1].



Appendix 2. Gradient and Fluid Density of Fluids within selected interval in Kunmi-1 Well.

According to Stocks ([3]), the relationship between hydrocarbon densities and pressure gradients can be expressed as:

$$Fluid\ density\ (g/cc) = {Gradient}/{0.433} \quad (1)$$

Where:

$$Gradient = {\Delta P_{fm}}/{\Delta Depth} \quad (2)$$

Where:

ΔP_{fm} = change in formation pressure (psi), and

$\Delta Depth$ = change in depth (ft)

From Figure 7, the gradient of the green line is given as:

$$Gradient = {3068.6 - 3024.4}/{4884 - 4746}$$

$= {44.2}/{138} \quad = 0.320\ psi/ft$. This value indicates oil.

$Fluid\ density = {0.320}/{0.433} \quad = 0.739\ g/cc$

For the second green line,

$$Gradient = {3252.8 - 3203.5}/{5227 - 5090}$$

$= {49.3}/{137} \quad = 0.359\ psi/ft$. This value suggests oil.

$Fluid\ density = {0.359}/{0.433} \quad = 0.830\ g/cc$

For the third line (blue),

$$Gradient = {3303.6 - 3271.6}/{5348 - 5277}$$

$= {32}/{71} \quad = 0.450\ psi/ft$. This value, unlike the previous values, is indicating fresh water.

$Fluid\ density = {0.450}/{0.433} \quad = 1.03\ g/cc$

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