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Porosity-Permeability Regimes Analysis For Hydrocarbon Exploration In An Onshore Niger Delta Sedimentary Basin

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Abstract **- The petrophysical analysis of any reservoir is a critical input necessary for petrophysical evaluation of the reservoir in any given field. There are different petrophysical parameters obtainable in any reservoir characterization but two major parameters needed for proper evaluation of the reservoir economics and productivity is the porosity and permeability. This study evaluates the porosity – permeability of the reservoir in a sedimentary basin (K-field) of onshore Niger Delta Basin, Nigeria. The porosity permeability regime was evaluated in the K-field with the aim of predicting the reservoir quantity and quality for hydrocarbon production. Different well logs were utilized, which included gamma ray log for lithology identification, resistivity log for fluid delineation, and the neutron and density log for hydrocarbons identification across the four wells within the reservoir. Two major lithologies were identified in the reservoir, namely sand and shale bodies. Six reservoir sand bodies were correlated across the four wells in the field. The average shale volume thicknesses recorded ranges between 9% to 25% within the different sand bodies (Sand A, Sand B, Sand C, Sand D, Sand E, Sand F and Sand G respectively), while the Net to Gross (N/G) values ranges between 77.25% to 90.75% respectively across the identified sand bodies. The effective porosity determined within the sand bodies ranges between 0.16 to 0.24 with the minimum in sand C and maximum in sand B, the permeability values obtained across the sand bodies are 381.74mD (Sand A), 937.62mD (Sand B), 373.96mD (Sand C), 869.88mD (Sand D), 933.56mD (Sand E), 745.81mD (Sand F) and 967.64mD (Sand G) respectively. The porosity permeability values were used to determine the water saturation in the reservoir sand bodies and the values obtained ranges from a minimum value of 46% in sand E to a maximum of 99% in C, with an equivalent oil saturation value that ranges between 54% and 1% respectively. The cross plot of the porosity and permeability regime (analysis) revealed a strong positive correlation, confirming that the reservoirs are clastic rocks as opposed to carbonate reservoirs originally suggested, the porosity permeability analysis also revealed a decreasing depth trend as a result of normal compaction. The results obtained for the porosity and permeability analysis of the reservoir in K-field can be classified as good to excellent, thus the field can be produced at an optimal production rate for significant and economics profits.**

Keywords—Porosity, Premeability, Water saturation, Shale Volume, Regime, Delination, Discrimination, Cross plots.

I. INTRODUCTION

The nature and geometry of reservoir rocks containing oil and gas dictates the quantities of fluids trapped within the void space of these rocks, and the ability of these fluids to flow through the rock pore spaces as well as other related physical properties. The measurement of void space in the rock is defined as the porosity of the rock, while the measurements of its ability to allow the rock transmit the fluid is called permeability [16].

Porosity and permeability of a rock are two very important parameters necessary for effective reservoir characterization and management [10,11,13]. Therefore, accurate knowledge of their distribution in the reservoir is essential in order to answer questions concerning types of fluids, amount of fluids, rates of fluid flow and fluid recovery. Their importance is reflected by the number of available techniques typically used for their estimation which includes well log evaluation, core measurements and well testing [1, 2, 5]. Porosity and permeability measurements from cores acquired in-situ are direct measurement of these properties, but a reservoir without core data is often associated with uncertainties as these properties have to be log derived. In the oil and gas industry, these reservoir properties are used to determine whether a well should be completed and put to production [3]. Porosity and permeability are also essential in overall reservoir management and development, such as choosing the optimal drainage points and production rate, optimizing completion and perforation design, and devising enhanced oil recovery patterns and injection conditions [5, 20].

Porosity which is a measure of reservoir storage capacity is defined as the proportion of the total rock volume that is void and filled with fluids. Porosity is a relative measurement and commonly expressed in decimal/fractional units or as a percentage, while permeability is the capacity of a reservoir rock to permit fluid flow and it is a function of the interconnectivity of the pore volume. Permeability of a formation is affected by factors such as porosity, pore space characterization, rock matrix composition, size of matrix grains, rock matrix composition, size of matrix grains and types and distribution of clay minerals [4,13].

Even though permeability is a very important reservoir property, it is the most difficult property to determine and predict. Several researchers have proposed different models for permeability determination in an un-cored reservoir using well logs [6,12,17,18,21]. All the above-mentioned models are based on correlation between permeability, porosity and irreducible water saturation.

This study is aimed to analyze the porosity and permeability regime in the reservoirs of K-Field, Onshore sedimentary basin of Niger Delta Area.

THEORETICAL BACKGROUND

There are two types of properties that will be used in reservoir characterization, these are petrophysical properties (porosity, shale volume, water saturation, permeability) and seismic - rock physics properties (elasticity, wave velocity). Some major approaches or a technique needed to characterize a given reservoir is basically performed using well logs data to calculate such needed properties.

Porosity (ϕ): this is the void or space inside the rock; they are very useful to store fluids such as oil, gas and water. They are also able to transmit those fluids to a place with lower pressure if they are permeable. Porosity calculation is one of the steps used for well log analysis. The most common method used to calculate porosity is neutron density log [5,15].

$$\phi = \frac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}} \qquad 1$$

Major and common types of porosity are: Absolute porosity, Effective porosity and total porosity. Porosity values can be obtained using either neutron or density logs [.5,16]

Fluid Saturation (S_{fl}): This is the fraction of the formation pores volume occupied by formation Fluid. The pore of any formation must be saturated with fluid and the summation of the fluid saturations in any given formation rock must be 100%, there are two major form of fluid saturation namely Water saturation and hydrocarbon saturation, although other fluid can be present apart from water or hydrocarbon (such as carbon dioxide, air etc.). No formation can have zero water saturation irrespective of the hydrocarbon content [15]. For water saturation we have

$$S_w = \left(\frac{a * R_w}{T_t * \phi^m} \right)^{\frac{1}{n}} \qquad 2$$

Shales Volume (V_{sh}):

This is the volume of shale formation and this can be calculated using any of the following method. The gamma ray log has several nonlinear empirical responses as well a linear response. The nonlinear responses are based on geographic area or formation age. All nonlinear relationships are more optimistic that is they produce a shale volume value lower than that from the linear equation [15].

For Linear response

$$V_{sh} = IGR = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \qquad 3$$

While for nonlinear response (Larionov, 1969), we have

Stieber Model: $$V_{sh} = \frac{IGR}{3 - 2IGR} \qquad 4$$

Clavier:

$$V_{sh} = 1.7\sqrt{3.38 - (IGR + 7)}^{2} \qquad 5$$

Larionov:

$$V_{sh} = 0.038(2^{(3.7*IGR)} - 1) \qquad 6$$

Permeability k: defined as the rock's ability to transmit fluid, higher permeability shows that the rock is able to transmit fluid easily and it means that the more hydrocarbon that can be produced daily, it is affected by many factors, such as shale volume, effective porosity and many other

$$K = 100x\frac{\phi^2 x(1 - Swirr)}{Swirr} \qquad 7$$

STUDY AREA

The study area is K-field located in the Onshore Eastern Niger Delta Basin. The field is defined by its seismic data coverage on the base map and extends from latitudes $4^0$35'00"N to $4^0$39'00"N and longitudes $6^0$16'00"E to $6^0$20'00"E. The map of the study area with the base map showing the wells distribution within the K field is shown in Figure 1. The Niger delta is a large, arcuate delta of the typical, wave- and tidal-dominated type [7,8,9]. It is located in the Gulf of Guinea on the margin of West Africa, at the southern culmination of the Benue trough and extends from about latitudes 4^0 to 6^0 N and longitudes 3^0 to 9^0 E. The delta formed at the site of a rift triple junction related to the opening

of the southern Atlantic starting in the Late Jurassic and continuing into the Cretaceous [19, 22].

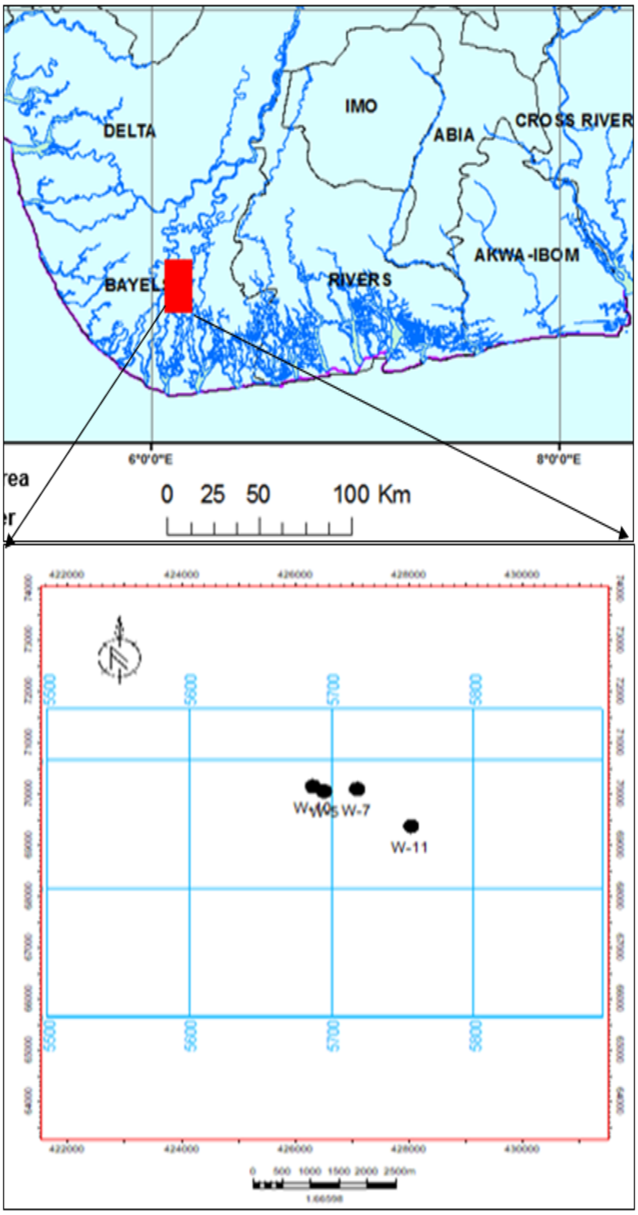

Figure 1: Map of Niger Delta Area, Nigeria showing the location of K-Field and the Base map of the study area showing the distribution of wells within the K-field.

II. MATERIALS AND METHODS

This study was conducted using well log data obtained (recorded) from K-field, onshore Niger Delta Area (study area). Summary of the dataset available are shown in table 1.

TABLE 1: Data inventory showing the available log dataset for this study

Well Name	Well Header	Log Header	Well Deviation	Gamma Ray	Resistivity	Neutron	Density	Sonic
W-5	YES	YES	YES	YES	YES	YES	YES	YES
W-7	YES	YES	YES	YES	YES	YES	YES	NO
W-10	YES	YES	YES	YES	YES	YES	YES	YES
W-11	YES	YES	YES	YES	YES	YES	YES	YES

The petrophysical evaluation workflow consists of shale volume (Vsh), total porosity (Φ_T), water saturation (Sw), effective porosity (Φ_E) and permeability (K). Various equations applicable to the Niger Delta formations were utilized for their computations. The study used standard equations for the respective parameters stated above.

III. RESULTS AND DISCUSSION

RESULTS

The reservoir logs were analyzed and the results obtained identified various lithologies present in the reservoir and this was correlated across the four wells in K-field has shown in Figure 3, while the results of petrophysical properties estimated for the reservoir sands identified across the field are presented in Table 2 - 5 for the respective wells. A comprehensive summary of the petrophysical properties are tabulated in Table 6. The logs generated for the shale volume, total and effective porosity, fluid type, fluid saturation and permeability are presented in Figures 4, 5, 6, 7 and 8, while the graphical plots of average gross thickness, shale volume and the net sand thickness for six reservoir intervals in the wells is shown in Figure 9. The average effective porosity and fluid saturation across the field is presented in Figure 10, while the graphical plot of average permeability estimated across the field is shown in Figure 11. The cross plots of porosity and permeability against depth is shown in Figure 12a and 12b respectively, while the cross plots of porosity against permeability is shown in Figure 13.

DISCUSSION

Using the gamma ray log motif, two main electrofacies were identified namely sands and shales bodies (Figure 3). The gamma ray logs within the sandy intervals show several serrations which is indicative of tidal influences. Each sand body is bounded by shales which act as cap rocks for the underlying reservoir sand, with a total of six sand bodies identified within the reservoir, namely Sand A, B, C, D, E, F and G respectively. The gross thickness of the reservoir sand bodies observed varies from

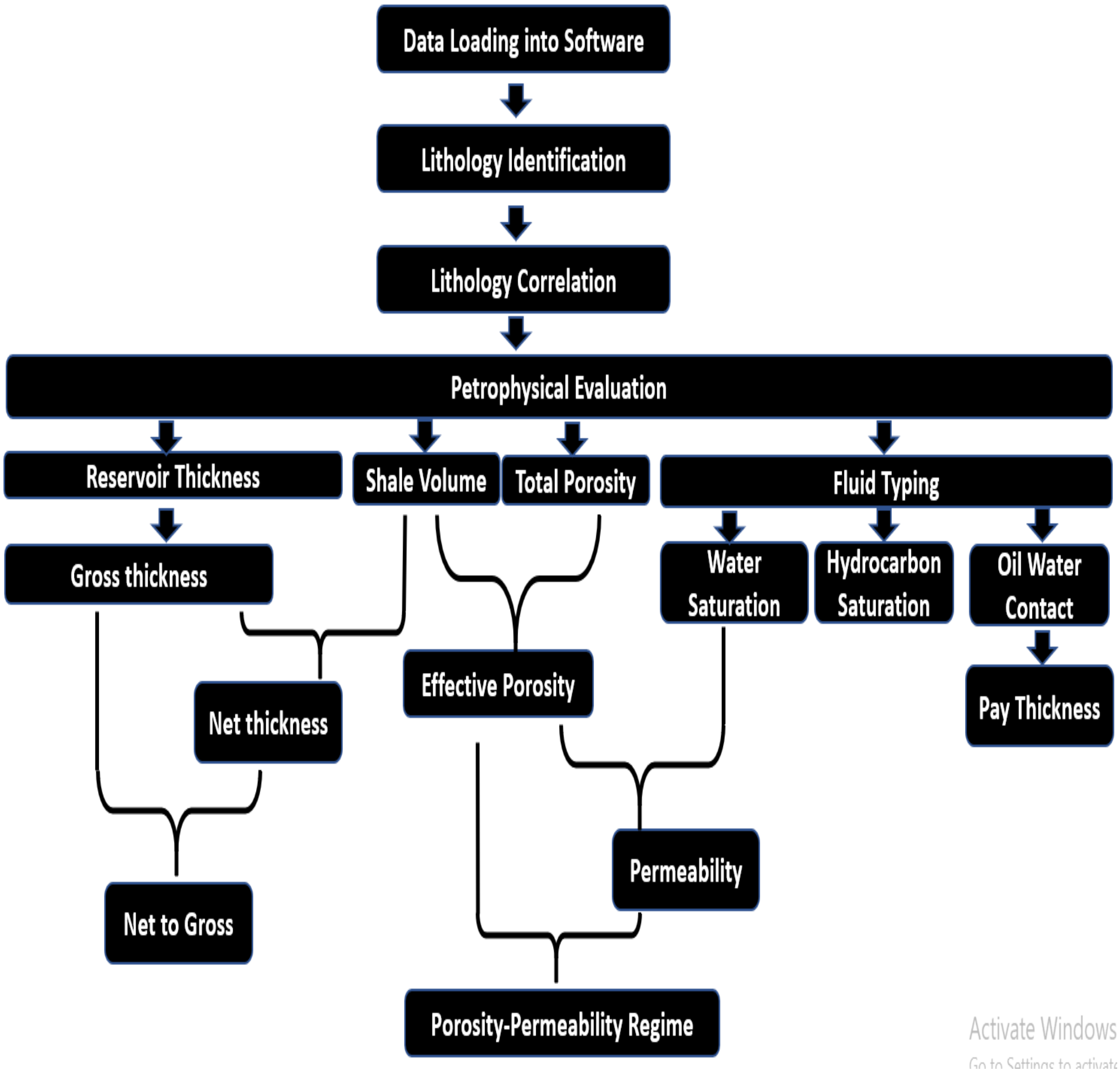

Figure 2: Workflow adopted for this study

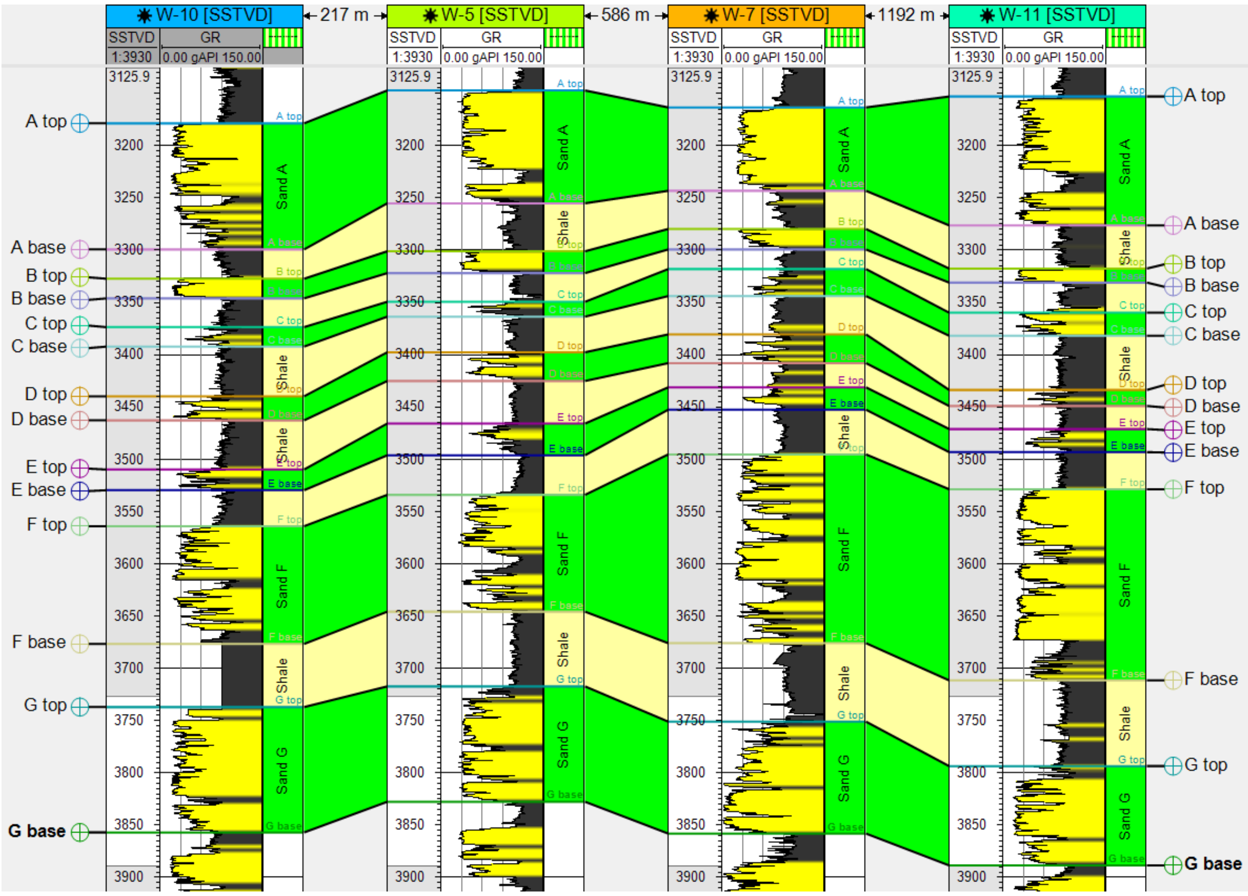

Figure 3: Lithofacies identified in K-field using well logs

Table 2: Results of petrophysical evaluation for reservoir sand intervals in well W-5

Reservoir sands	Top (m)	Base (m)	Gross thickness (m)	Shale volume (%)	Net to Gross (frac.)	Total Porosity (frac.)	Effective Porosity (frac.)	Water saturation (frac.)	Permeability (mD)	Hydrocarbon saturation (frac.)	Fluid type	Fluid contact	Pay thickness (m)
Sand A	3171	3271	100	0.16	84.40	0.25	0.21	0.80	549.92	0.20	Oil and Water	OWC=3174 m	3.00
Sand B	3323	3341	18	0.09	91.00	0.26	0.24	0.56	1252.90	0.44	Oil	ODT	16.38
Sand C	3372	3383	11	0.26	74.00	0.20	0.15	0.99	530.65	0.01	Water	WUT	nil
Sand D	3418	3444	26	0.30	70.00	0.25	0.18	0.38	1149.38	0.62	Oil and Water	OWC=3441 m	23.00
Sand E	3486	3515	29	0.32	68.00	0.21	0.15	0.47	817.83	0.53	Oil and Water	OWC=3502 m	16.00
Sand F	3555	3665	110	0.22	78.00	0.22	0.18	0.56	895.69	0.44	Oil and Water	OWC=3642 m	87.00
Sand G	3763	3847	84	0.10	90.00	0.22	0.20	0.31	1220.14	0.69	Oil and Water	OWC=3835 m	72.00

OWC – oil water contact; ODT – oil down to; WUT – water up to

Table 3: Results of petrophysical evaluation for reservoir sand intervals in well W-7

Reservoir sands	Top (m)	Base (m)	Gross thickness (m)	Shale volume (%)	Net to Gross (frac.)	Total Porosity (frac.)	Effective Porosity (frac.)	Water saturation (frac.)	Permeability (mD)	Hydrocarbon saturation (frac.)	Fluid type	Fluid contact	Pay thickness (m)
Sand A	3167	3243	76	0.14	86.00	0.24	0.22	0.99	582.92	0.01	Water	WUT	nil
Sand B	3279	3298	19	0.10	90.00	0.22	0.21	0.21	1165.34	0.79	Oil	ODT	19.00
Sand C	3318	3344	26	0.22	78.00	0.19	0.17	0.99	440.48	0.01	Water	OWC=3326 m	8.00
Sand D	3382	3407	25	0.24	76.00	0.23	0.12	0.31	1103.23	0.69	Oil	ODT	25.00
Sand E	3431	3451	20	0.31	69.00	0.22	0.20	0.24	654.80	0.76	Oil	ODT	20.00
Sand F	3496	3675	179	0.19	81.00	0.20	0.18	0.45	923.14	0.55	Oil and Water	OWC=3568 m	72.00
Sand G	3755	3858	103	0.11	89.00	0.21	0.19	0.51	1345.66	0.49	Oil and Water	OWC=3810 m	55.00

OWC – oil water contact; ODT – oil down to; WUT – water up to

Table 4: Results of petrophysical evaluation for reservoir sand intervals in well W-10

Reservoir sands	Top (m)	Base (m)	Gross thickness (m)	Shale volume (%)	Net to Gross (frac.)	Total Porosity (frac.)	Effective Porosity (frac.)	Water saturation (frac.)	Permeability (mD)	Hydrocarbon saturation (frac.)	Fluid type	Fluid contact	Pay thickness (m)
Sand A	3193	3292	99	0.21	78.70	0.25	0.20	-	-	-	-	-	-
Sand B	3340	3359	19	0.06	94.00	0.26	0.24	-	-	-	-	-	-
Sand C	3391	3401	10	0.26	74.00	0.18	0.14	-	-	-	-	-	-
Sand D	3458	3474	16	0.15	85.00	0.25	0.21	-	-	-	-	-	-
Sand E	3523	3542	19	0.15	85.00	0.23	0.20	-	-	-	-	-	-
Sand F	3580	3677	97	0.14	86.00	0.23	0.20	-	-	-	-	-	-
Sand G	3763	3869	106	0.07	93.00	0.23	0.21	0.39	1190.10	0.61	Oil and Water	OWC=3830 m	67.00

OWC – oil water contact

Table 5: Results of petrophysical evaluation for reservoir sand intervals in well W-11

Reservoir sands	Top (m)	Base (m)	Gross thickness (m)	Shale volume (%)	Net to Gross (frac.)	Total Porosity (frac.)	Effective Porosity (frac.)	Water saturation (frac.)	Permeability (mD)	Hydrocarbon saturation (frac.)	Fluid type	Fluid contact	Pay thickness (m)
Sand A	3179	3301	122	0.12	88.00	0.25	0.23	0.99	45.37	0.01	Water	WUT	nil
Sand B	3345	3356	11	0.06	94.00	0.23	0.22	0.99	307.07	0.01	Water	WUT	nil
Sand C	3387	3408	21	0.13	87.00	0.23	0.20	0.99	60.59	0.01	Water	WUT	nil
Sand D	3464	3476	12	0.25	75.00	0.21	0.16	0.89	310.87	0.11	Oil and Water	OWC=3467 m	3.00
Sand E	3500	3518	18	0.19	81.00	0.23	0.19	0.44	1165.03	0.56	Oil and Water	ODT	14.58
Sand F	3558	3705	147	0.09	91.00	0.24	0.22	0.80	446.05	0.20	Oil and Water	OWC=3609 m	51.00
Sand G	3827	3924	97	0.10	90.00	0.24	0.22	0.87	240.18	0.13	Oil and Water	OWC=3838 m	11.00

OWC – oil water contact; ODT – oil down to; WUT – water up to

TABLE 6: Statistical summary of petrophysical evaluation for reservoir sand intervals across the field

Reservoir sands	Gross thickness (m)	Shale volume (%)	Shale volume (m)	Net sand (m)	Net to Gross (frac.)	Total Porosity (frac.)	Effective Porosity (frac.)	Water saturation (frac.)	Permeability (mD)	Hydrocarbon saturation (frac.)
Sand A	105.25	0.16	16.73	88.52	83.88	0.25	0.21	0.86	381.74	0.14
Sand B	16.50	0.08	1.26	15.24	92.50	0.25	0.24	0.70	937.62	0.30
Sand C	13.25	0.23	2.76	10.49	77.25	0.20	0.16	0.99	373.96	0.01
Sand D	20.00	0.25	5.25	14.75	75.00	0.24	0.18	0.55	869.88	0.45
Sand E	23.75	0.25	6.21	17.54	75.50	0.22	0.17	0.46	933.56	0.54
Sand F	116.00	0.17	18.80	97.20	83.25	0.23	0.20	0.64	745.81	0.36
Sand G	92.75	0.09	8.48	84.27	90.75	0.23	0.21	0.47	967.64	0.53

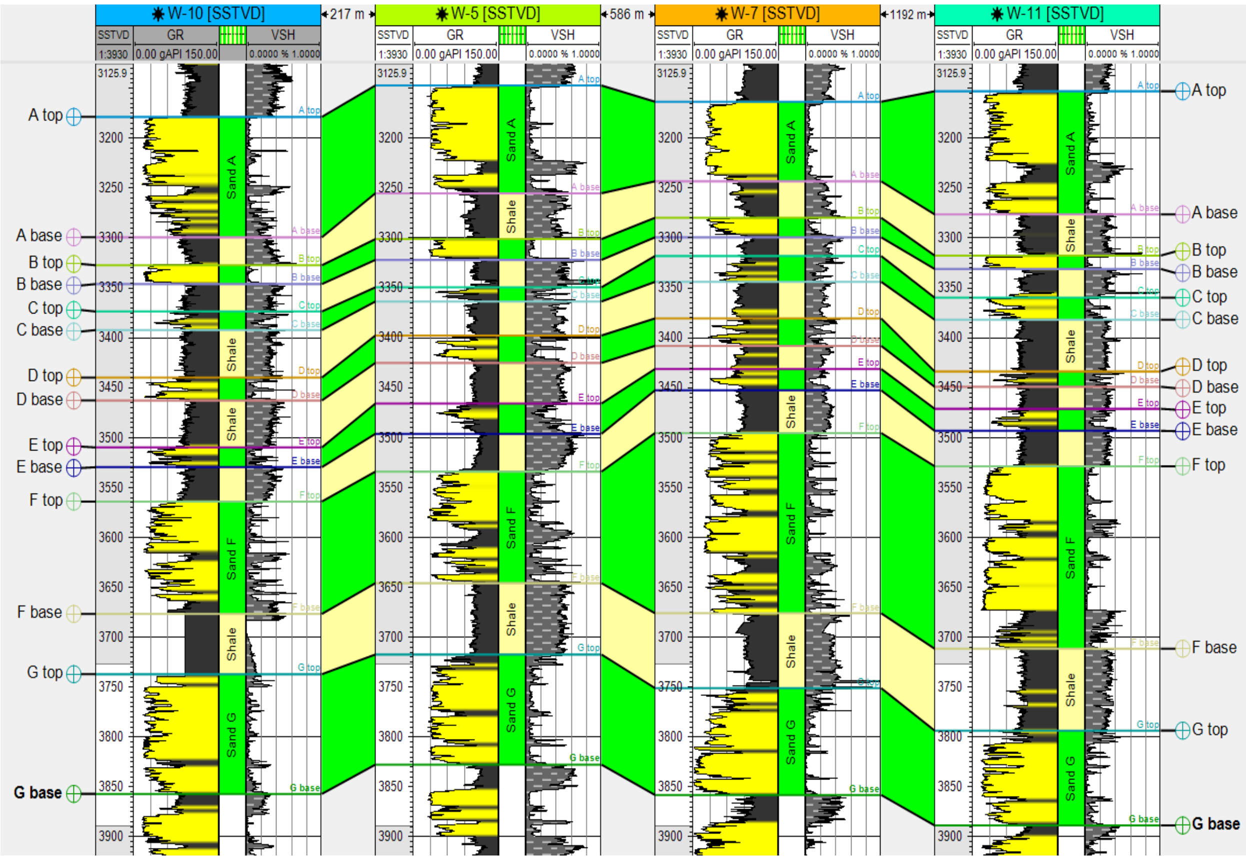

Figure 4: Shale volume log estimated in K-field using well logs

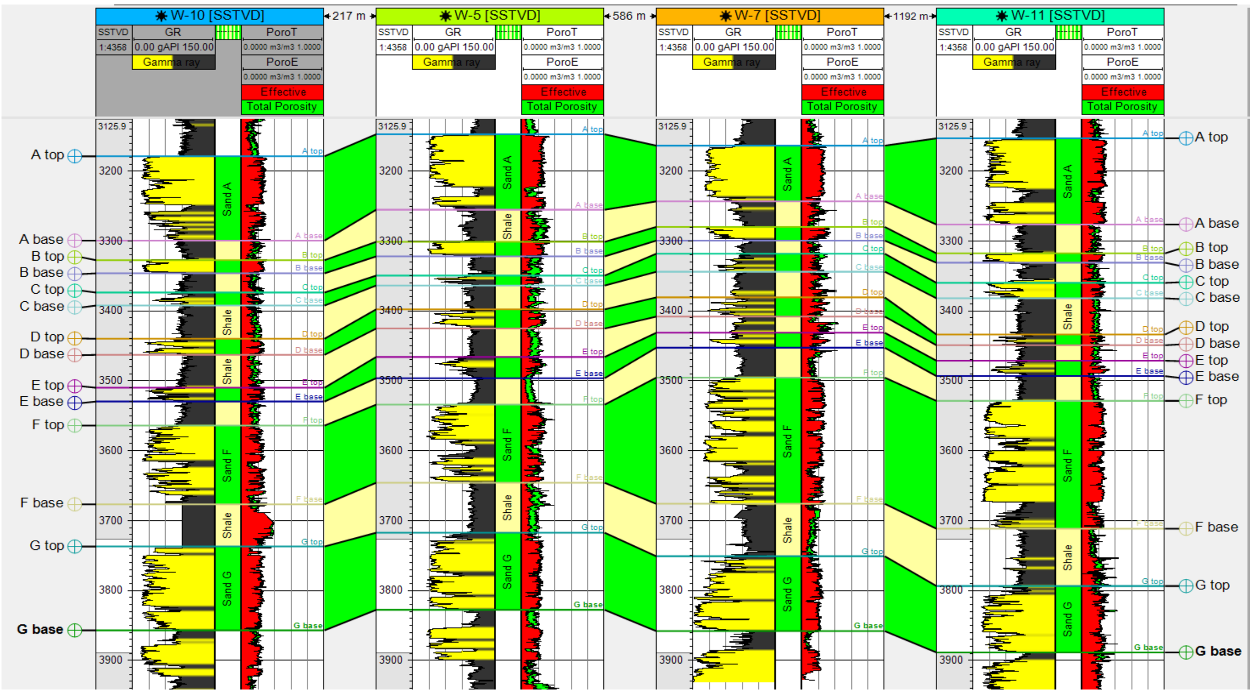

Figure 5: Total and effective porosity logs estimated in K-field using well logs

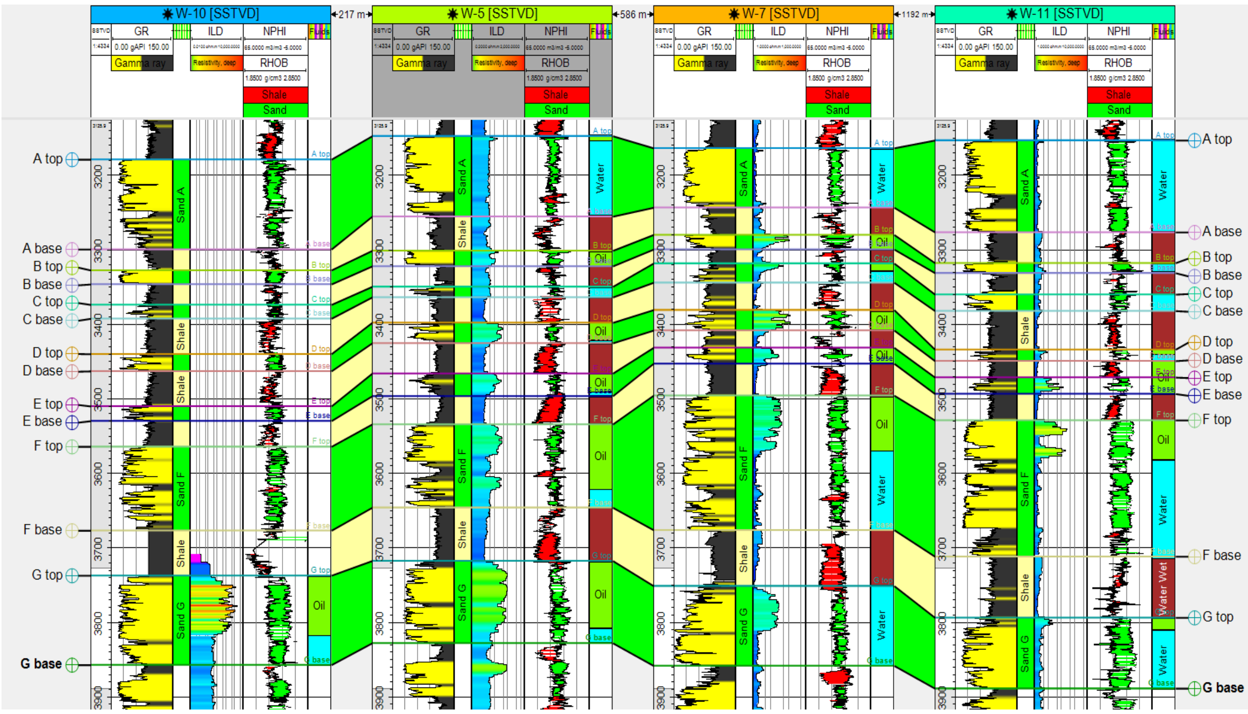

Figure 6: Fluid types estimated in K-field using well logs

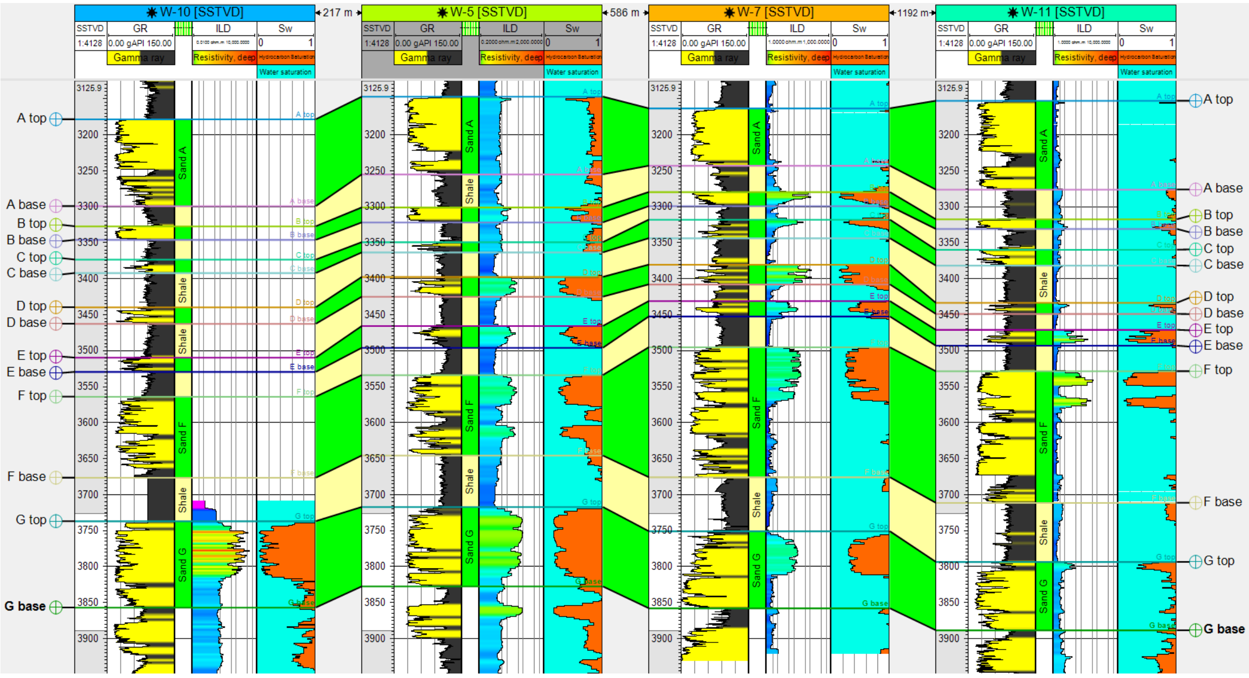

Figure 7: Fluid saturation logs estimated in K-field using well logs

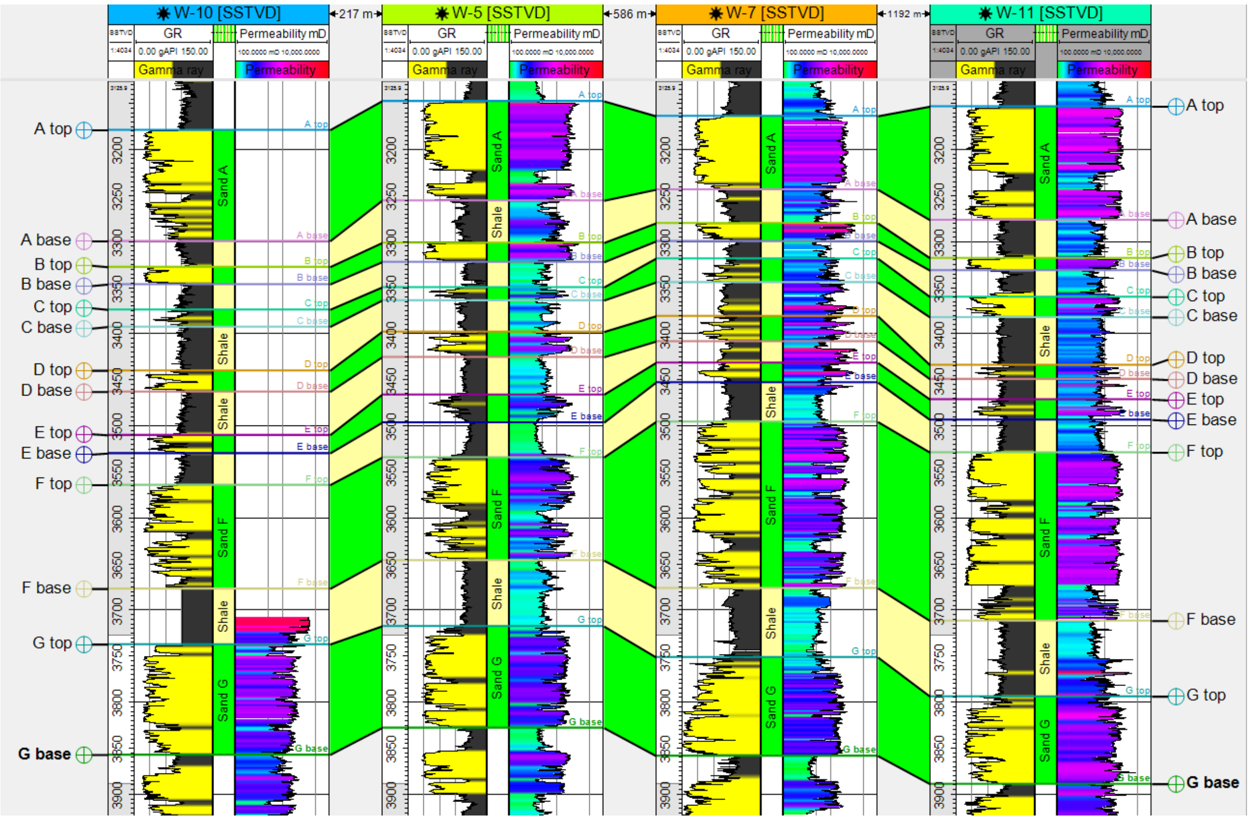

Figure 8: Permeability log estimated in K-field using well logs

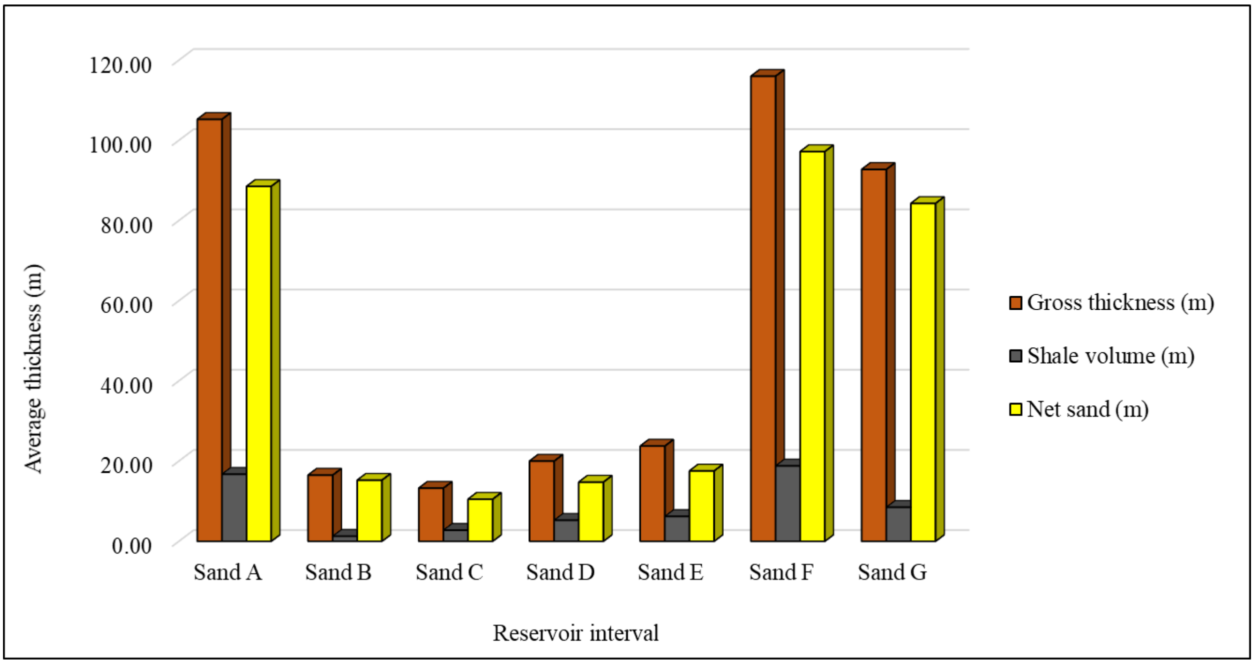

Figure 9: Average gross thickness, shale volume and net sand thickness across the field

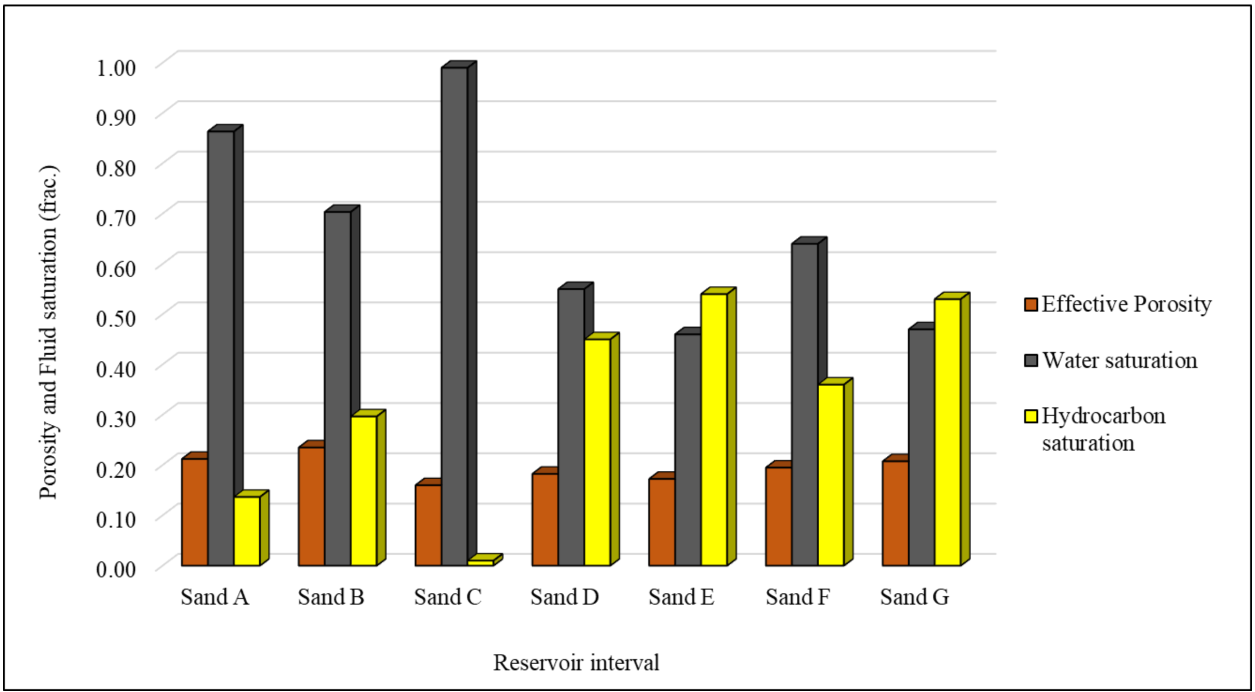

Figure 10: Average effective porosity and fluid saturation across the field

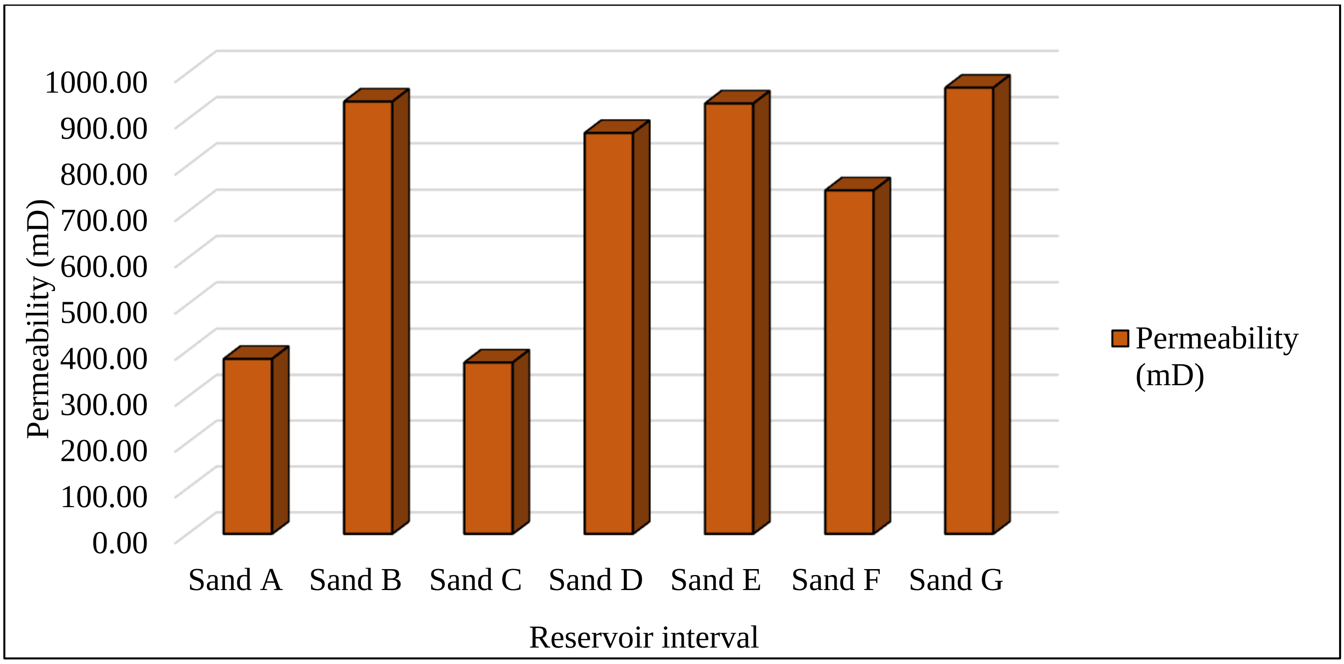

Figure 11: Average permeability estimated across the field

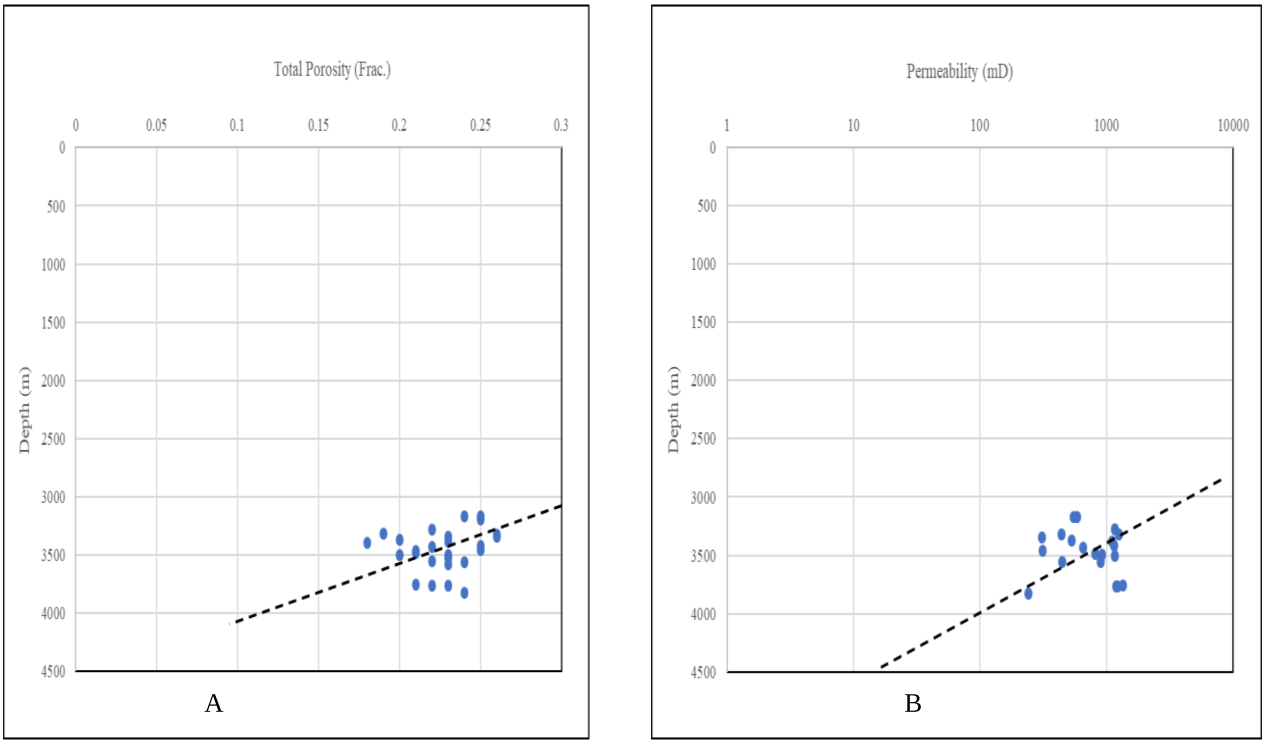

Figure 12: (A) Cross-plot of porosity versus depth for reservoirs in K-field. (B) Cross-plot of permeability versus depth for reservoirs in K-field.

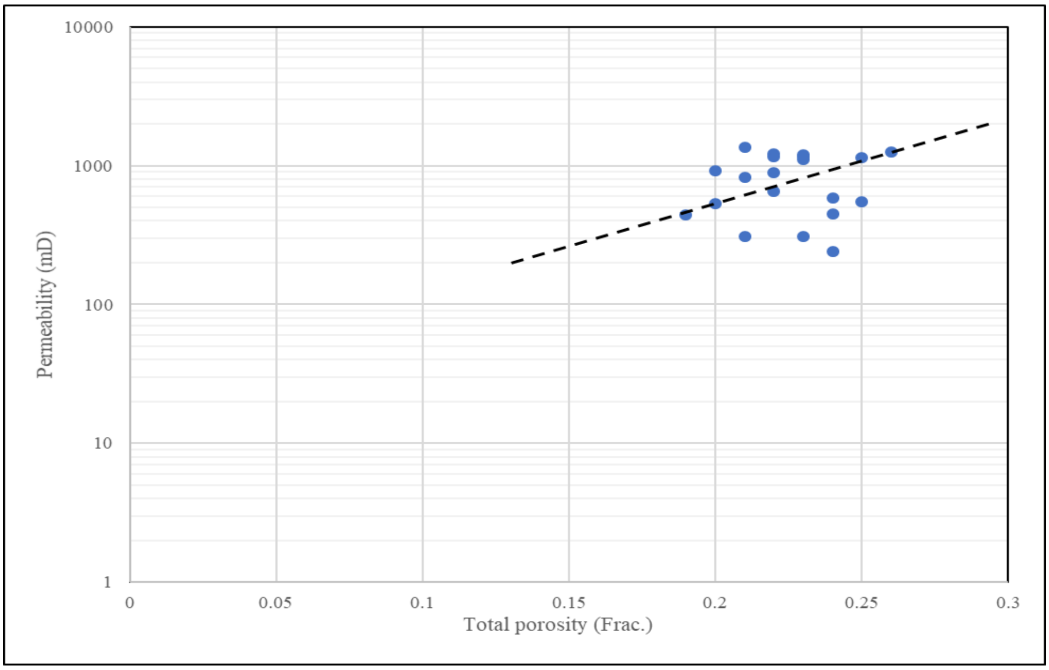

Figure 13: Cross-plot of porosity versus permeability for reservoirs in K-field

from one well to another across the field, with an average gross thickness of 105.25m in sand A, 16.50m in sand B, 13.25m in sand C, 20.00m in Sand D, 23.75m in sand E, 116.00m in sand F and 92.75m in sand G respectively. The results show that reservoir sand F has the largest thickness while sand C has the lowest thickness, while the average shale volume thicknesses varies as 16%, 8%, 23%, 25%, 25%, 17% and 9% in the respective sand bodies (Figure 4). It was observed that the higher the shale volume in the reservoir sand, the poorer the quality of the reservoir rock. Although reservoir sand C, D and E have the highest shale volumes, all the reservoir sands have shale volumes below 30% of the entire gross thickness. This shows that the reservoir sands are predominantly clean. The average reservoir net thickness which is the producible portion of the reservoir sand are 88.52m, 15.24m, 10.49m, 14.75m, 17.54m, 97.20m and 84.27m respectively, these results show that the reservoirs have sufficient thicknesses suitable for hydrocarbon accumulation. The average Net to Gross (N/G) ratio (in %) in the respective sand bodies varies as 83.88%, 92.50%, 77.25%, 75.00%, 75.50%, 83.25% and 90.75% respectively in the reservoir intervals, the results shows that over 70% of the entire gross reservoir interval thickness are available as clean sand for hydrocarbon accumulation (Table 2-5).

The average total porosity determined in reservoir sands varies as follow 0.25 in sand A, 0.25 in sand B, 0.20 in sand C, 0.24 in sand D, 0.22 in sand E, 0.23 in sand F and 0.23 in sand G respectively, while the average effective porosity calculated from empirical models varies as 0.21, 0.24, 0.16, 0.18, 0.17, 0.20 and 0.21 in the respective corresponding sand bodies (Figure 5). The effective porosity is a major factor responsible for hydrocarbon production. Using the following reservoir classification according to Rider (1986) [classified reservoir quality based on porosity as follows; <5% (negligible), 5-10% (poor), >10-20% (good), >20-30% (very good), >30 (excellent)], the total porosity recorded in this study is classed as very good while effective porosity is classed as ranging from good to very good. Generally, porosity decreases with depth in K-field (Table 6).

The average permeability results determined in the reservoir intervals in this study shows that sand A has a value of 381.74mD, sand B- 937.62mD, sand C- 373.96mD, sand D- 869.88mD, sand E- 933.56mD, sand F- 745.81mD and sand G- 967.64 mD respectively, and using Rider's (1986) classification of reservoir quality based on permeability [Below-10mD (poor to fair), 10-50mD (moderate), 50-250mD (Good), 250-1000mD (very good) and above 1000mD (excellent)], the reservoirs intervals in K-field can be classed as having very good permeability, which shows that flows can easily occur through the reservoir.

Similarly, porosity and permeability plots against depth revealed a decrease in these two reservoir properties with depth. The porosity-permeability cross plot for reservoirs identified across four wells in the K-field revealed a positively correlated trend. As porosity increases in these reservoirs, the permeability of the reservoirs also increases. This positively correlated trend between porosity and permeability is typical of clastic reservoirs, unlike carbonate reservoirs where there is no significant relationship between porosity and permeability.

CONCLUSION

This study utilized well logs for evaluating the porosity permeability regimes in K-field, onshore Niger Delta. Lithologies identified using the gamma ray logs were sands and shales, while six reservoirs intervals were identified and correlated across the field (Sand A to Sand G). Petrophysical evaluation of all the identified reservoir intervals revealed that their gross thicknesses are sufficient enough for hydrocarbon accumulation in economic quantities. The Shale volumes were found to be below 30% in all the reservoirs. The total porosity recorded are very good (above 20%), while the effective porosity was found to be good to excellent (above 15%) for the various reservoir intervals. Permeability is classed as very good for all reservoir intervals (above 380.00mD), while the water saturation varied but generally decreases with depth, hence more hydrocarbon saturations were found at deeper reservoir intervals.

The cross plot of porosity and permeability revealed a strong positive correlation existing between the two variables, suggesting that the reservoirs are clastic reservoirs as opposed to carbonate reservoirs where no significant trend can easily be identified. This study has shown that the reservoir intervals evaluated in this study have the necessary requirement to be termed good reservoir rocks with sufficient hydrocarbon bearing intervals. Generally, porosity and permeability regime in the reservoir are classified as good to excellent; hence, the field can be produced optimally for significant and economics profit.

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