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Depositional environment and reservoir quality appraisal of offshore 'K-Field', Niger Delta, Nigeria

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Abstract

This study attempts to evaluate the hydrocarbon reservoir and depositional trend of 'K- Field' via suites of wireline logs. This is to identify, correlate the sand bodies and evaluate their petrophysical attributes with a view of understanding their variation as itaffects the reservoir, hydrocarbon prospect and productivity in the field, and to determine the palaeoenvironment of the lithofacies. Six sand bodies were identified and correlated across three wells. Zones of sand level with water saturation < 0.50 were the hydrocarbon bearing. The various hydrocarbon reservoirs determined are six (W-7), four (W-2) and three (W-11) respectively. The average petrophysical properties of the reservoirs range from 19% to 25%, 54.84 md to 1159.90 md, 20% to 42% and 58% to 80% for porosity, permeability, water saturation and hydrocarbon saturation respectively. The porosity and permeability range from good to excellent. The identified reservoirs show high movable oil saturation (MOS), low residual oil saturation (ROS) and favourable values of movable hydrocarbon index (*Sw/Sxo< 0.7)*. The field has both oil and gas hydrocarbon with the Gas Oil Contact (GOC), Oil-Water-Contact (OWC), Oil-Down-To (ODT) and Gas-Down-To (GDT) contact types. The cross plot of water saturation and porosity revealed that the grain sizes of the sand bodies range from coarse to very fine. Bulk Volume Water (BVW) cross plot indicated that most of the reservoirs are heterogeneous and not at irreducible water saturation. The log facies recognized suggest a palaeo-depositional environment of basin plain, crevasse splay, prograding and transgressive marine shelves.

Keywords: Porosity; lithofacies; logs; palaeoenvironment; petrophysical; reservoir.

Introduction

The search for hydrocarbon has developed with the application of greater sophisticated methods to evaluate the probability of hydrocarbon potentials thereby limiting the risk factor associated with hydrocarbon. The entire hydrocarbon produced comes from the accumulation in the pore spaces of reservoir rocks (sandstone, limestone, or dolomite) [1]. Hydrocarbon is produced in the Niger Delta, Nigeria, in an unconsolidated sands of the Agbada Formation characterized by intercalation of sand and shale units with varying thicknesses from 100 ft (30 m) to 15,0000 ft (4,600 m) [2]. These sands are the main hydrocarbon reservoirs while the shale provide both lateral and vertical seals. Since the well log analysis could convert raw log data (log suites)into estimated quantities of oil, gas and water in a formation [3, 4], this study therefore attempt to evaluate the petrophysical parameters, depositional pattern, palaeoenvironment and correlation of the reservoir sand bodies in the 'K-Field'. This is expected to provide insight into the reservoirs' settings, hence the integration of this study with other data could guide in the identification of pore pressure zones and enhance exploration, exploitation and development of the reservoir sand bodies in the field of study [4].

Location of the study area and geological setting

The 'K-Field' is an offshore field located off the western coast of the Niger-Delta in the Gulf of Guinea (Figure 1). The Niger Delta is a prolific basin and province believed to have a sediment thickness of 12 km at the central portion with an area extent of about 75,000 km^2[5]. It extends between Longitude 3^o and 9^{o}E and Latitudes 4^o and 6^{o}N. The Niger-Benue and

Cross River are the sources of the sedimentary fill of the basin and other distributaries that are prograding into the Atlantic Ocean. These fills gave rise to the three formations which characterize the basin consisting of unconsolidated sands and over pressured shales. While the sands are fluvial to fluvio-marine (channels and barrier bars respectively), the shales are fluvial marine or lagoonal.

The Niger Delta is made up of three lithostratigraphic units which are the Benin, Agbada and Akata Formations (Figure 2) [6]. The Benin Formation is the youngest and uppermost unit made up of thick fresh water-bearing massive continental sands and gravels which are deposited in the upper deltaic plain environment. Brackish water and marine faunas are absent in this formation. It is about 2,000 m thick and the sands are yellowish due to the presence of feldspar, limonite and hematite.

The Agbada Formation is aparalic sequence which comprises of intercalation of sand and shale layers; it underlies the Benin formation and is about 4,500 m thick. It contains bulk of the known hydrocarbon accumulation in the Niger-Delta and is also associated with growth faults.

The Akata Formation is the oldest unit underlying the Agbada Formation, it is marine in origin, contain thick shale sequence (potential source rock), turbidites and (potential reservoir in deep water) and small amount of silt and clay, it is under-compacted and over-pressured.

Data set and methodology

The data sets include suites of wireline logs from three wells (W-2, W-7 and W-11), Checkshot data for W-2 and the software used was Schlumberger Petrel software. The delineation and correlation of sand bodies

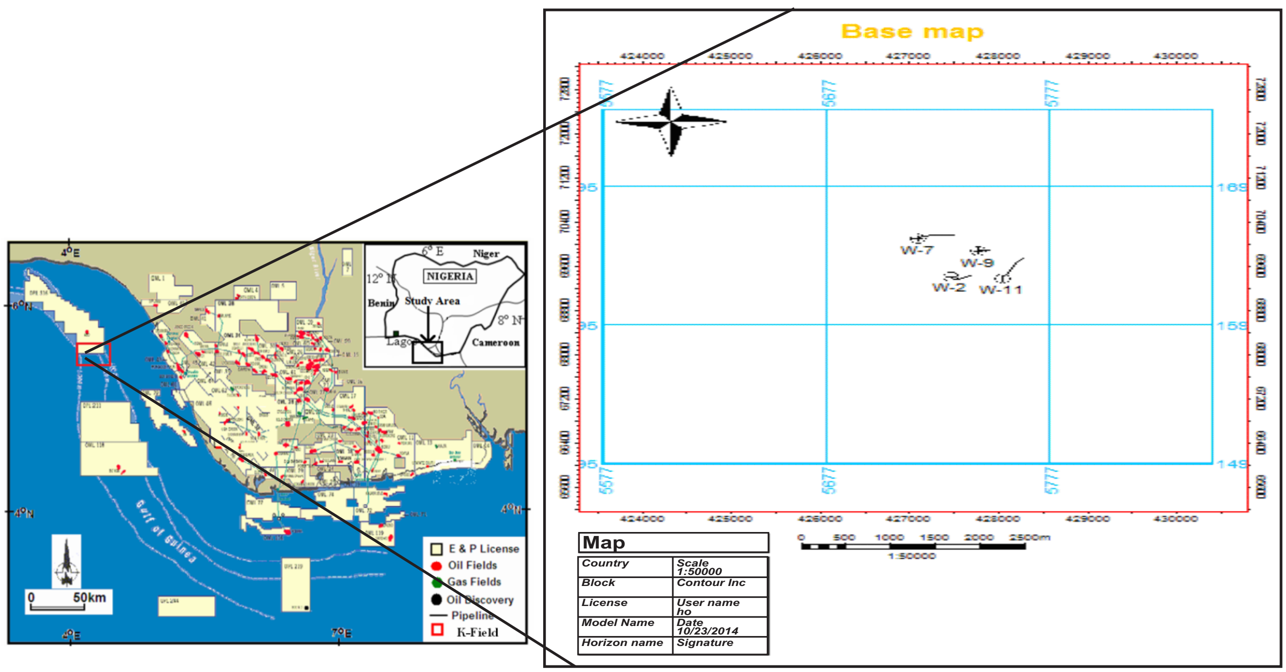


Figure 1. The 'K- Field' and well locations of the study-area.

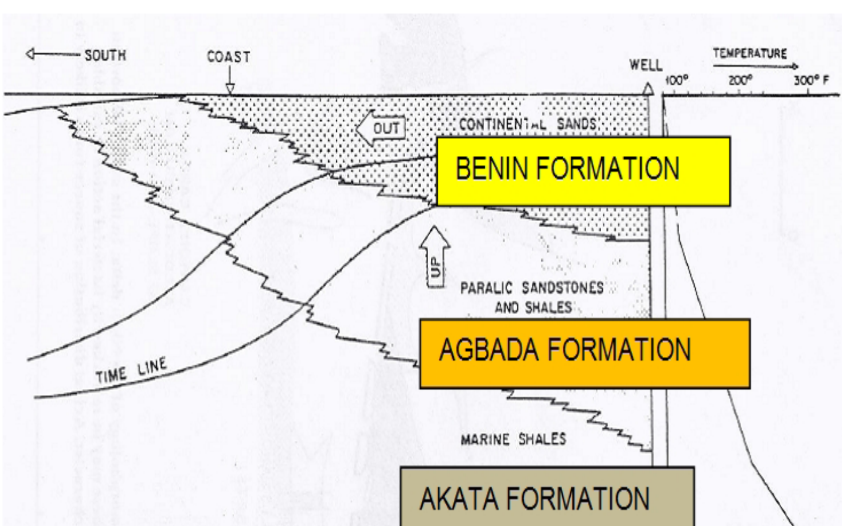


Figure 2. Lithofacies of Niger Delta Basin [6].

across the wells was carried out based on the positions of the reservoir in the succession of sands and shales on the logs across the wells. The gamma ray (GR) logs was used in determining the lithofacies and in well correlation because it exhibits patterns that are easier to recognize and correlate from well to well, the shale resistivity markers (SRM) were then identified on the three wells using the resistivity log because shales are deposited in low energy environment and occur over a wide area. The SRM were used to cross-check the correlation of the GR log and the reservoir sand bodies were found to be continuous. The correlation was done from the top to the bottom of the well.

Petrophysical analysis

The petrophysical parameters calculated from the logs using various empirical formulas and their arithmetic weighted average obtained for each zone includes:

- *Gamma ray index*

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \quad \text{. . . . (1)}$$

- *Volume of shale*

For the Tertiary rocks:

$$V_{sh} = 0.083[2^{(3.7 \text{ x IGR})} - 1.0] \quad \text{. . . . (2)}$$

- *Total porosity*

$$\Phi_D = (\text{RhoM} - \text{RHOB}) / (\text{RhoM} - \text{RhoF}) \quad \text{. . . . (3)}$$

$$Ø_{N\text{-}D} = \sqrt{\frac{ØN^2 + ØD^2}{2}} \quad \text{. . . . (4)}$$

- *Effective porosity*

This was computed to remove the effect of shale present:

$$Øe = Ø_{N\text{-}D} * (1\text{-}V_{sh}) \quad \text{. . . . (5)}$$

- *Formation factor*

This is a constant of proportionality that relates the resistivity of a clean water bearing formation to the resistivity of brine in which it is fully saturated.

where a = 0.62 and m = 2.15 for sandstone.

$$F = a/Ø^m \quad \text{. . . . (6)}$$

- *Formation water resistivity* (Rw) (&!m)

This was calculated using picket plot or looking for clean water saturated zone and then calculating apparent water resistivity:

$$R_{wa} = R_o/F \quad \text{. . . . (7)}$$

- *Water saturation of the uninvaded zone*

The equation was used:

$$S_W = \left(\frac{F \times R_w}{R_t}\right)^{1/n} \quad \text{. . . . (8)}$$

- *Hydrocarbon Saturation*

This was calculated by:

$$S_{h=} 1 - S_w \quad \text{. . . . (9)}$$

- *Bulk Volume Water*(BVW)

When BVW values are constant or near constant, a zone is at irreducible water saturation:

$$BVW = S_w \text{ x } Ø_{N\text{-}D} \quad \text{. . . . (10)}$$

- *Irreducible water saturation*

At irreducible water saturation water will not move, and the relative permeability to water is zero. It is a term used to describe the water saturation at which all the water is held back by capillary pressure:

$$S_{wirr} = (F/2000)^{1/2} \quad \text{. . . . (11)}$$

- *Permeability (K)*

It was calculated using:

$$K = 0.136{*}Ø^{4.4}/S_{wirr} \quad \text{. . . . (12)}$$

- *Net to gross ratio*

This is the ratio between net reservoir thickness and gross reservoir thickness:

$$NTG = 1 - V_{sh} \quad \text{. . . . (13)}$$

- *Water (mud filtrate) saturation of the flushed zone* (S_{xo})

In the flushed zone of moderate invasion and average residual hydrocarbon saturation, the equation below is valid:

$$S_{xo} = S_w^{1/5} \quad \text{. . . . (14)}$$

- *Movable Oil saturation* (MOS):

$$MOS = S_{xo} - S_w \quad \text{. . . . (15)}$$

- *Residual hydrocarbon saturation* (S_{hr})

$$S_{hr} = 1 - S_{xo} \quad \text{. . . . (16)}$$

- *Hydrocarbon movability index* **(**HMI)

When HMI is less than 0.7 for sandstone, movable hydrocarbons are indicated:

$$HMI = S_w \text{ D } S_{xo} \quad \text{. . . . (17)}$$

Determination of fluid types

The formation density and neutron logs was used for the differentiation of the various fluid types and the gas zones was interpreted from the porosity logs (RHOB and NPHI) via the normal shale reading. Water zones and oil zones will be determined based on the tracking of both logs where water zone has low resistivity and high water saturation value, while an oil zone has a high resistivity and low water saturation value [7].

Determination of palaeodepositional environments

Prediction of depositional environment can be based on sandstone compositions, grain sizes characteristics (textures), spontaneous potential (Figures 3 and 4), and gamma ray log motifs [8, 9].

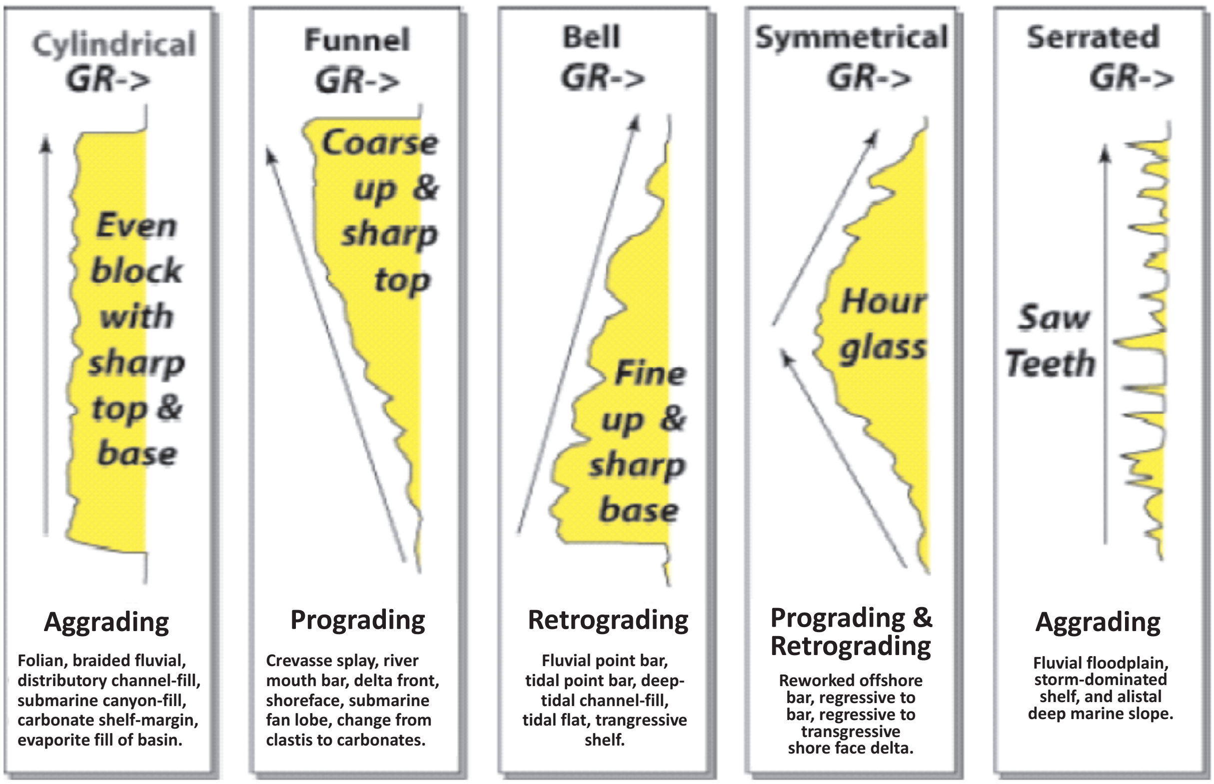


Figure 3. Gamma ray response [8].

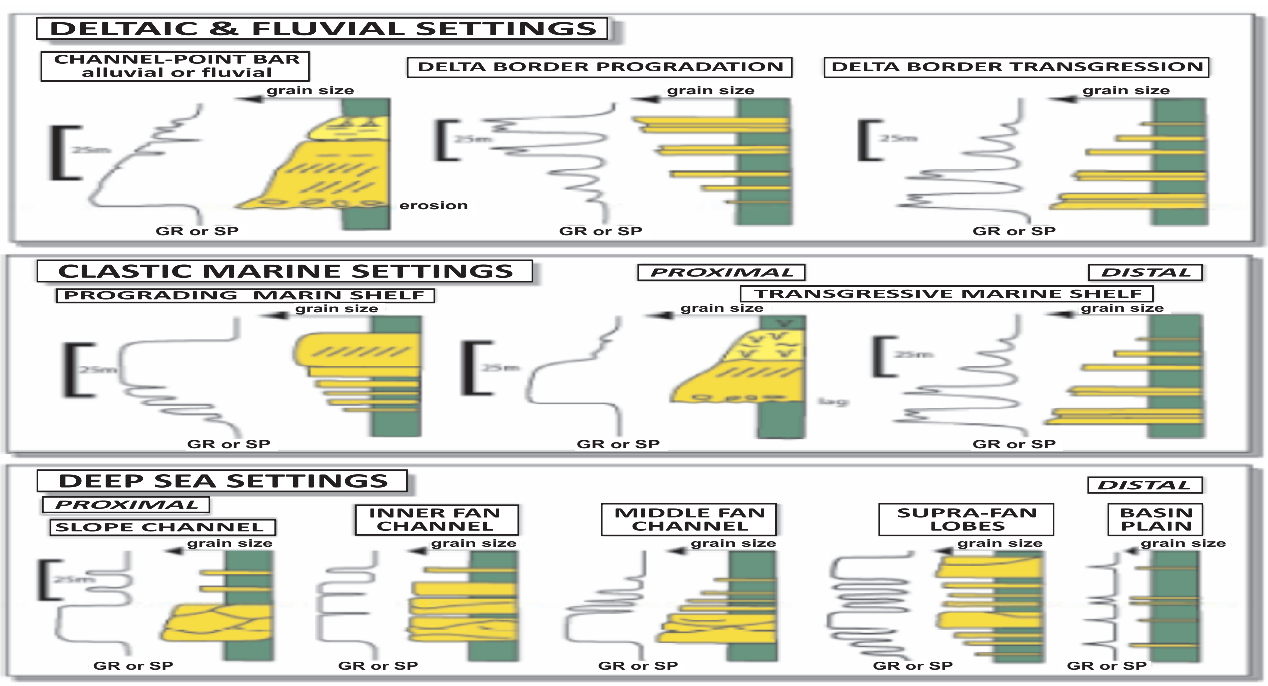


Figure 4. Gamma ray response and depositional setting [9].

Results and discussion

From the correlation, it was observed that sand bodies F1 to F6 are correlatable in all the wells in the field while F7 sand is only correlatable in wells W-7 and W-2, thus implying that the correlatable sand bodies are genetically equivalent laterally. Some of the sand bodies correlated do not contain hydrocarbon (Figures 5 and 6).

Seven sand bodies (F1 to F7) were identified based on well log correlation and the variation of their petrophysical properties across the wells (W-7, W-2 and W-11) were evaluated. The sand bodies with water saturation values less than 0.50 were the hydrocarbon bearing sands while those with values more than 0.50 were the wet water bearing sands [10].

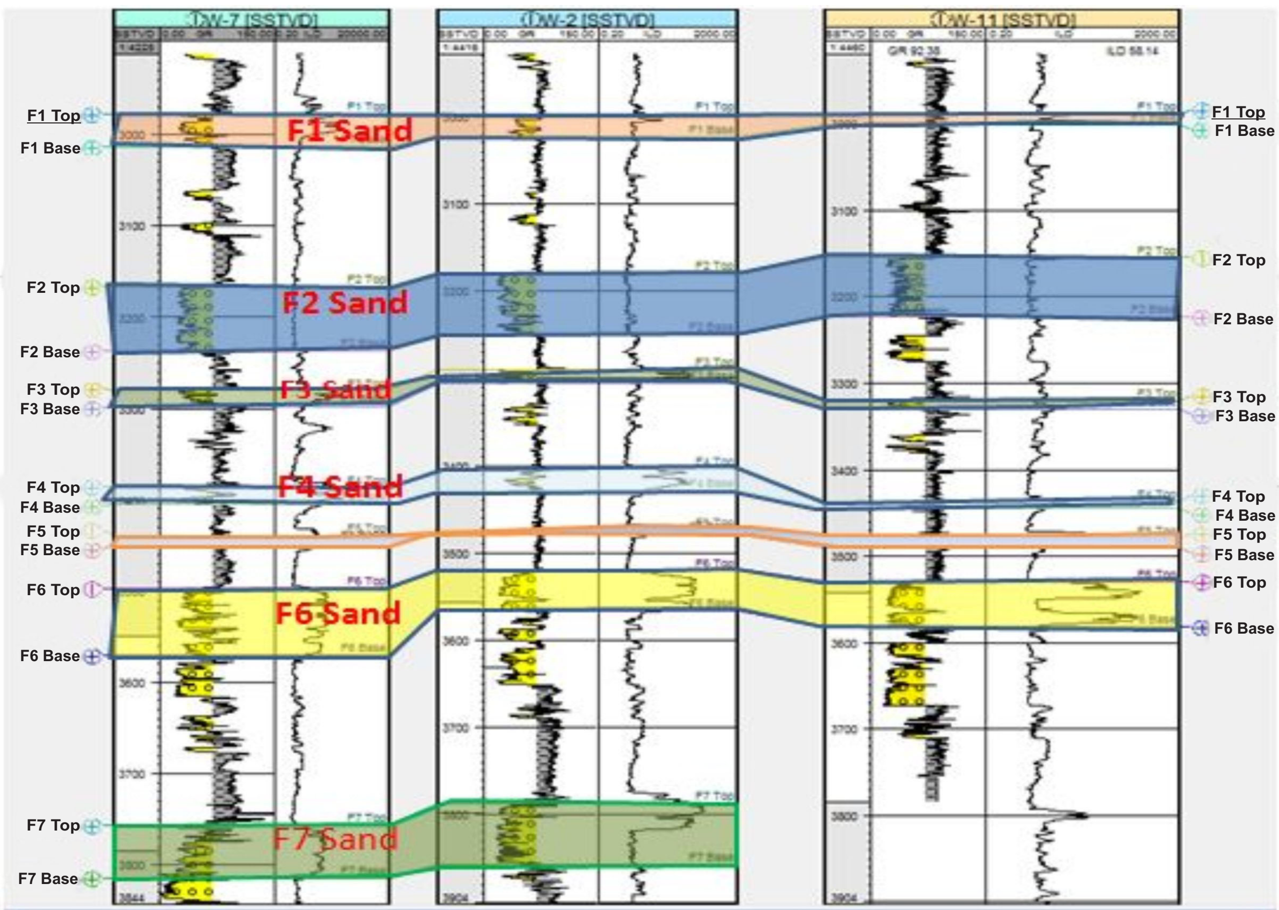


Figure 5. Stratigraphic correlation of the sand bodies in three wells.

Appraisal of F1 sand body across the studied wells (W-7, W-2, and W-11)

This reservoir has net thickness of 33.41 m, 21.58 m and 9.87 m in W-7, W-2 and W-11 respectively (Tables 1-4 and Figure 7). The effective porosity (Øe), permeability (K) and hydrocarbon saturation (S_h) across the wells range from 0.21- 0.25, 54.84-1159.9 md and 0.39-0.63 respectively. Wells W-7 and W-11 have S_w value less than 0.50. The Ø and K values are good to excellent [11] (Tables 3 and 4). The movable oil saturation (MOS) values are more than the ROS values which indicate high permeability to oil while the hydrocarbon movability index(HMI) (S_w/S_{xo}) values are less than 0.7 therefore the hydrocarbon will move during oil production (Tables 1-3). Bulk volume water (BVW) plot (S_w vs. Ø)shows that wells W-7, W-2 and W-11 are near irreducible S_w at 4%, 10-15% and 10-15% respectively, hence producing little water. Well W-7 encountered GOC at 2997m while both W-2 and W-11 wells have only oil (Figures 7-10) [12].

Appraisal of F3 sand body across the studied wells (W-7, W-2, and W-11)

This reservoir sand has net thickness range of 13.18 m to 15.13 m, with clean sand development evident from its low volume of shale 0.08 to 0.11v/v decimal (Tables 1-4 and Figure 7). The $Ø_e$, K,S_w and S_h across the wells range from 0.21 to 0.23, 17.57 md to 493 md, 0.28 to 0.86, and 0.14 to 0.72 respectively (Tables 1-3,). Wells W-7 and W-2 have S_w value less than 0.50. The Ø is very good while K values are moderate to good. The MOS values are more than the ROS value indicating good permeability to oil. The HMI values are less than 0.7; therefore, movable hydrocarbons are

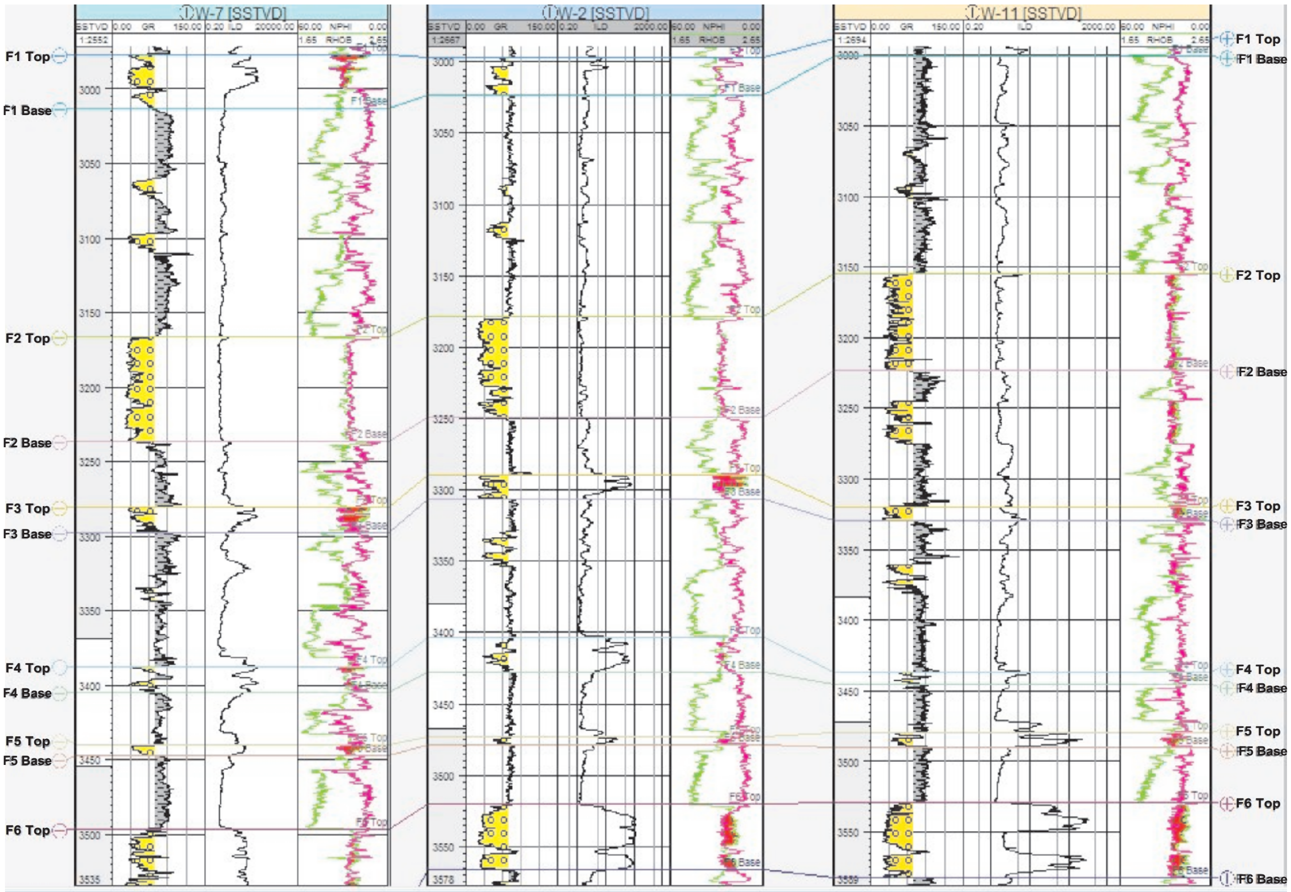


Figure 6. Neutron-density log showing fluid types and gas zones based on low neutron log and high density log readings.

indicated. BVW plot shows that F3 sands in wells W-7 and W-2 are heterogeneous and not at irreducible water saturation while it is homogeneous and the irreducible water saturation at 15% in well W-11, indicating that water free hydrocarbon will be produced. Gas Oil Contact (GOC) was encountered in W-7 and W-2 wells at 3,293.04 m and 3,302.10 m. W-11 well is wet though water free hydrocarbon could still be produced (Figures 7-10) [12].

Appraisal of F4 sand body across the studied wells (W-7, W-2, and W-11)

This reservoir horizon has thickness that range from 7.3 m to 19.64 m, the net to gross values are quite high with show good sand development (Tables 1-4 and Figure 7). The values of $Ø_e$, K, S_w and S_h across the wells range from 0.19 to 0.21, 21.28 md to 621 md, 0.21 to 0.72 and 0.28 to 0.79 respectively (Tables 1-3). The S_h decreases from W-7 to W-11 in the NW-SE trend direction. This may probably be as a result of fault displacement below the oil-water contact (OWC) of the hydrocarbon bearing F4 sand. Permeability and porosity are moderate to very good. W-7 and W-2 have S_w less than 0.50. The MOS values are higher than the residual oil saturation while the MOS values are less than 0.7 in W-7 and W-2 (Tables 1-3). A BVW plot shows that the F4 sand in all the wells is heterogeneous and more water cut hydrocarbon will be produced in W-11. F4 sand in W-7 encountered GOC at 3404.68 m, two OWC at 3410.50 m and 3421.26 m in W-2 while W-11 is wet Figures 7-10) [12].

Appraisal of F5 sand body across the studied wells (W-7, W-2, and W-11)

The F5 sand has a net thickness range of 4.47 m to 8.92 m, with an average of 6.66 m (Tables 1-4 and Figure 7). The effective porosity, permeability, water saturation and hydrocarbon saturation across the wells range from 0.19 md to 0.23 md, 70.74 md to 608.90 md, 28% to 30% and 70% to 72% respectively (Tables 1-3). The permeability and porosity range from good to very good(Table 4). The MOS values are more than the ROS values while the MHI values (0.09-0.36v/v decimal) are less than 0.7. Therefore, the hydrocarbon will move during production. BVW plot shows that F5 sand in W-7 is near irreducible water saturation and little water will be produced with the hydrocarbon while in W-2 and W-11, F5 sand is heterogeneous and not at irreducible water saturation. Gas column was Down-To (GDT) 3489.01 m in W-7, GDT 3500.60 m in W-2 and GDT 3470.33 m in W-11 (Figures 7-10) [12].

Table 1. Average petrophysical values of sand bodies in W-7 within the ‘K-Field’.

Sand	Top (MD) (m)	Bottom (MD) (m)	Gross Thickness (m)	Net Thickness (m)	Net Pay (m)	NTG	$Ø_{N\_D}$	$Ø_e$	S_w	BVW	K(md)	S_h	F	V_{sh}	S_{wirr}	HCPV	S_{xo}	MOS	ROS	MHI	Fluid type	Contact
F1	3015.25	3052.38	37.13	33.41	22.18	0.9	0.28	0.25	0.37	0.10	1159.9	0.63	11.28	0.1	0.07	0.16	0.78	0.41	0.22	0.43	Gas, Water	GWC
F2	3206.92	3280.52	73.6	68.44		0.93	0.27	0.25	0.94	0.25		0.06	11.54	0.07	0.08	0.01	0.99	0.44	0.01	0.96	Water	WET
F3	3322.02	3338.90	16.88	15.02	16.88	0.89	0.25	0.23	0.28	0.07	493.00	0.72	13.03	0.11	0.08	0.17	0.75	0.48	0.25	0.35	Gas, oil	GOC
F4	3429.09	3446.68	17.59	14.59	12.13	0.83	0.25	0.21	0.21	0.05	621.11	0.79	13.97	0.17	0.08	0.17	0.72	0.51	0.28	0.28	Gas, oil	GOC
F5	3481.69	3489.01	7.32	6.59	7.32	0.89	0.26	0.23	0.28	0.07	274.50	0.72	12.55	0.1	0.07	0.17	0.77	0.49	0.23	0.36	Gas	GDT
F6	3538.89	3612.56	73.67	64.09	70.33	0.87	0.25	0.21	0.20	0.07	218.10	0.8	13.84	0.13	0.08	0.15	0.78	0.47	0.22	0.38	Oil	ODT
F7	3756.47	3814.35	57.88	52.67	38.94	0.97	0.23	0.20	0.37	0.08	99.31	0.63	15.94	0.08	0.08	0.13	0.81	0.44	0.19	0.45	Oil	ODT

Table 2. Average petrophysical values of sand bodies in W-2 within the ‘K-Field’.

Sand	Top (MD) (m)	Bottom (MD) (m)	Gross Thickness (m)	Net Thicknes (m)	Net pay (m)	NTG	$Ø_{N\text{-}D}$	$Ø_e$	S_w	BVW	K (md)	S_h	F	V_{sh}	S_{wirr}	HCPV	S_{xo}	MOS	ROS	MHI	Fluid type	Contact type
F1	3019.82	3046.78	26.96	21.58	4.20	0.81	0.30	0.24	0.58	0.19	58.72	0.42	9.29	0.19	0.06	0.09	0.91	0.27	0.09	0.69	Water	WET
F2	3202.01	3276.86	70.85	63.76	-	0.90	0.28	0.25	0.92	0.26	-	0.08	10.45	0.1	0.07	0.02	0.98	0.06	0.02	0.93	water	WET
F3	3312.89	3329.89	17.00	15.13	11.77	0.89	0.25	0.22	0.38	0.10	259.35	0.62	12.89	0.11	0.08	0.14	0.80	0.42	0.2	0.44	Gas, oil	GOC
F4	3426.96	3451.76	24.80	19.34	16.13	0.78	0.26	0.20	0.30	0.08	262.62	0.70	12.33	0.22	0.07	0.15	0.77	0.47	0.23	0.38	Oil, Water	OWC
F5	3496.96	3502.62	5.66	4.47	5.42	0.79	0.24	0.19	0.30	0.09	70.74	0.70	13.99	0.21	0.08	0.12	0.82	0.43	0.18	0.09	Gas	GDT
F6	3543.64	3590.26	46.62	41.49	35.03	0.89	0.23	0.21	0.25	0.06	368.34	0.75	15.74	0.11	0.08	0.16	0.73	0.48	0.27	0.32	Gas, oil	GOC
F7	3810.69	3882.45	71.76	64.58	18.18	0.90	0.23	0.21	0.64	0.14	235.3	0.36	15.8	0.1	0.08	0.07	0.87	0.23	0.13	0.67	Water	WET

Table 3. Average petrophysical values of sand bodies in W-11 within the ‘K-Field’.

Sand	Top (MD) (m)	Bottom (MD) (m)	Gross Thickness (m)	Net Thickness (m)	Net pay (m)	NTG	$Ø_{N\_D}$	$Ø_e$	Sw	BVW	K (md)	S_h	F	V_{sh}	S_{wirr}	HCPV	S_{xo}	MOS	ROS	MHI	Fluid type	Contact type
F1	3010.13	3023.12	12.99	9.87	8.44	0.76	0.28	0.21	0.61	0.14	54.84	0.39	11.11	0.24	0.073	0.11	0.87	0.37	0.13	0.58	Water	Wat/ET
F2	3178.08	3248.39	70.31	66.09	-	0.94	0.25	0.24	0.93	0.24	-	0.07	12.86	0.05	0.079	0.02	0.98	0.06	0.02	0.94	Water	Wat/ET
F3	3344.43	3358.92	14.49	13.18	-	0.91	0.21	0.2	0.86	0.17	17.57	0.14	29.4	0.08	0.108	0.04	0.96	0.1	0.04	0.88	water	Wte/ET
F4	3464.75	3473.45	8.7	7.30	4.38	0.84	0.22	0.19	0.72	0.15	21.28	0.28	17.81	0.16	0.093	0.06	0.93	0.21	0.07	0.77	water	Wte/ET
F5	3508.82	3518.96	10.14	8.92	8.52	0.88	0.24	0.22	0.29	0.07	608.9	0.71	14.22	0.12	0.083	0.16	0.75	0.46	0.25	0.36	Gas	Gs DT
F6	3558.76	3612.32	53.56	50.88	40.26	0.95	0.22	0.21	0.42	0.09	420.1	0.58	16.84	0.05	0.091	0.12	0.8	0.37	0.2	0.48	Gas	Gs DT

Table 4. Qualitative evaluation of porosity and permeability of reservoir rocks [9, 11].

Percentage porosity (%)	Qualitative evaluation
0-5	Negligible
5-10	Poor
15-20	Good
20-25	Very Good
Over 30	Excellent
Average K value (mD)	**Qualitative description**
< 15	Poor to fair
15-50	Moderate
50-250	Good
250-1000	Very Good
> 1000	Excellent

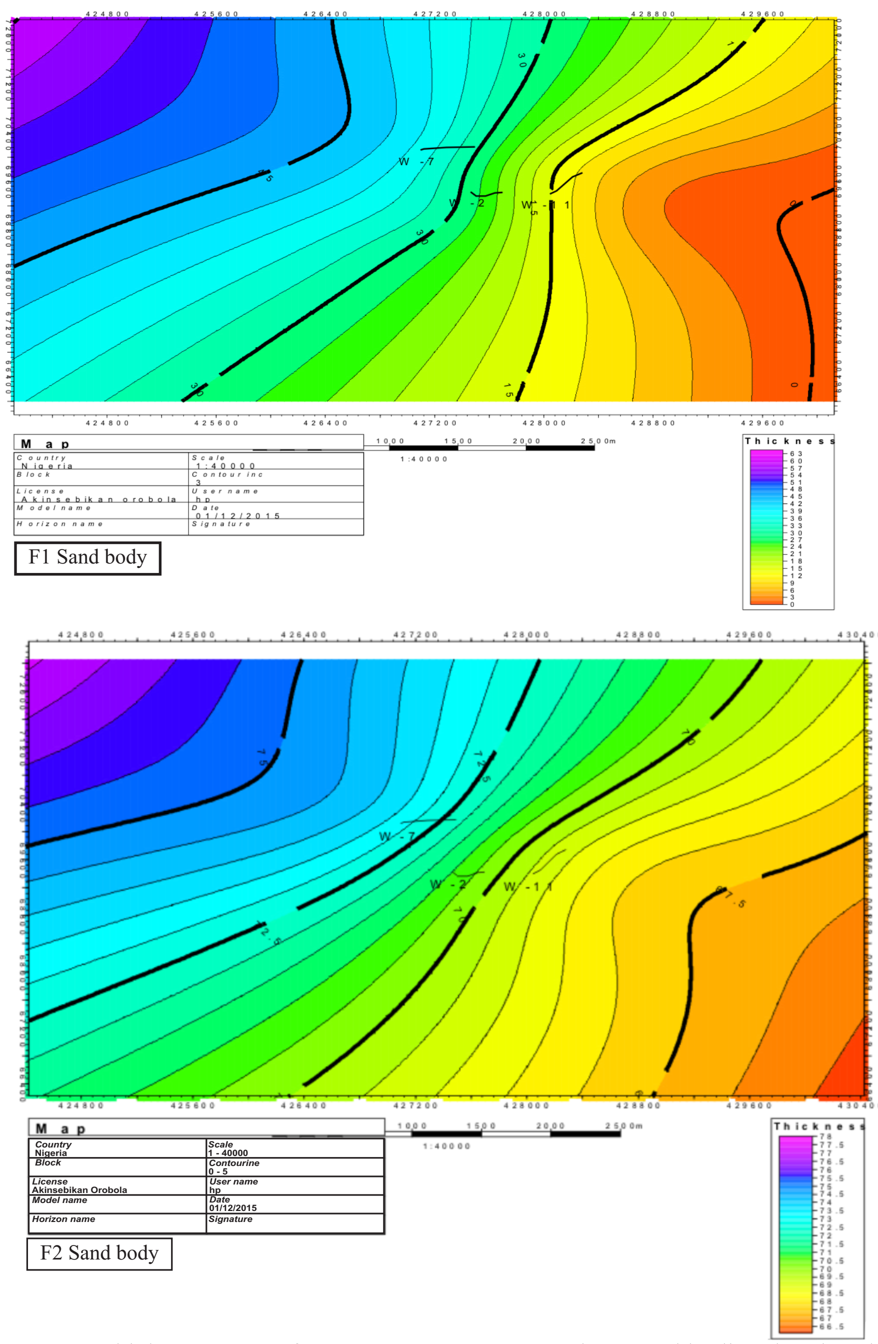


Figure 7. Thickness maps of F1, F2, F3, F4, F5, F6 and F7 Sand bodies showing the wells' locations.

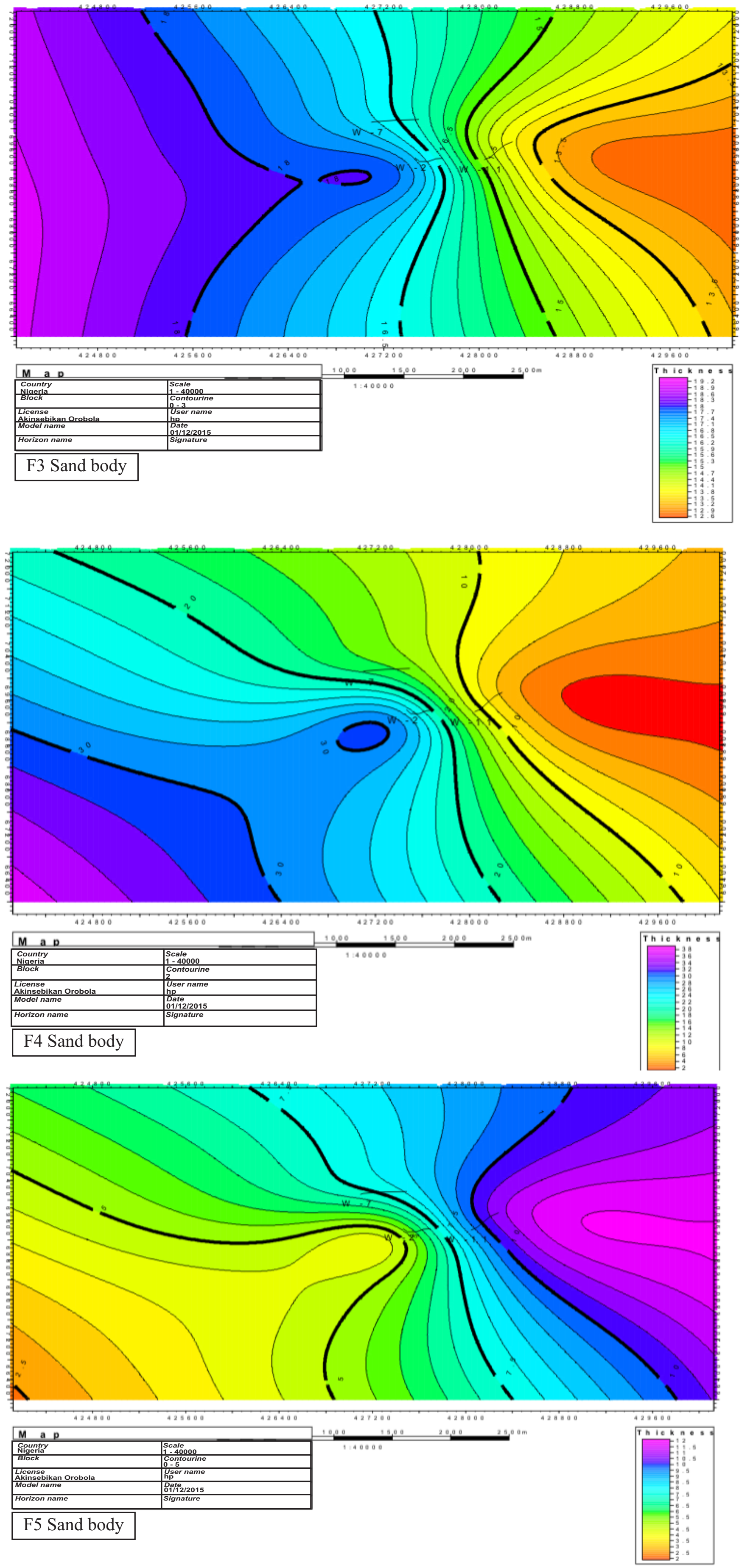
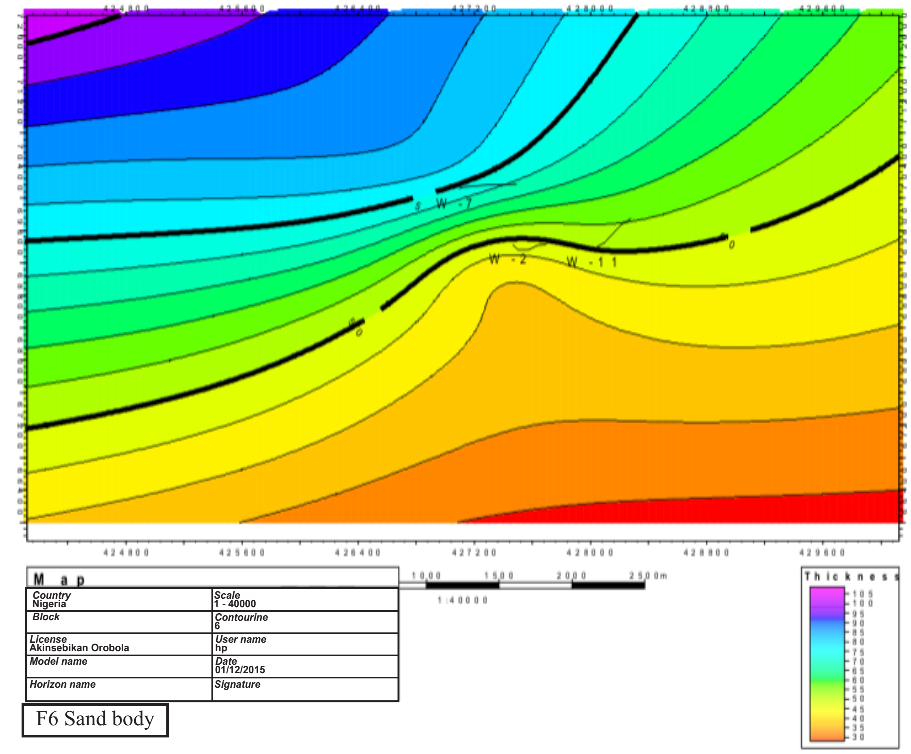


Figure 7 (cont’d). Thickness maps of F1, F2, F3, F4, F5, F6 and F7 Sand bodies showing the wells’ locations.



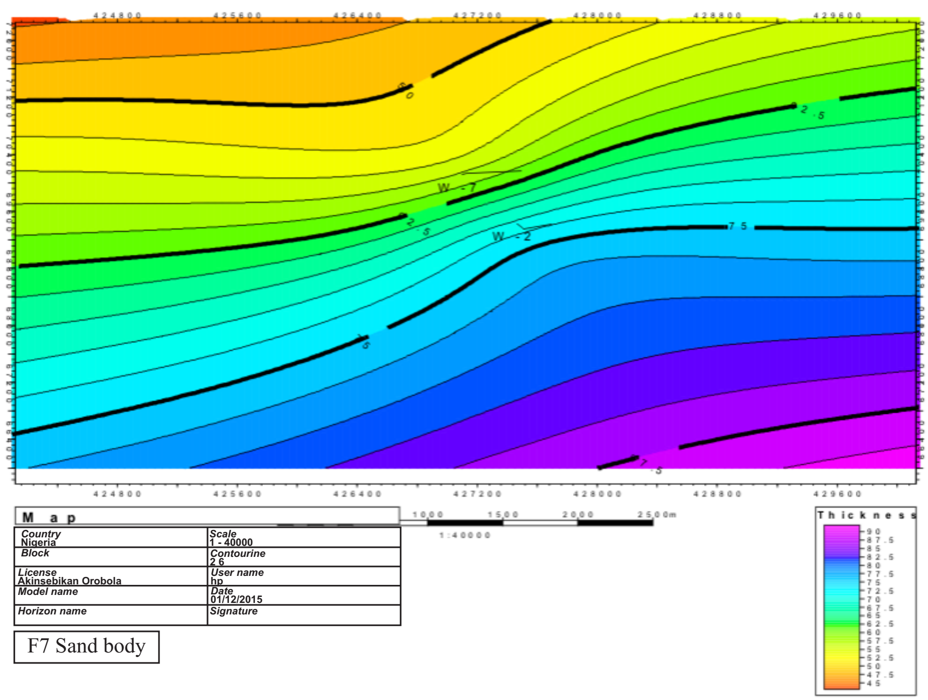


Figure 7 (cont'd). Thickness maps of F1, F2, F3, F4, F5, F6 and F7 Sand bodies showing the wells' locations.

Appraisal of F6 sand body across the studied wells (W-7, W-2, and W-11)

F6 sand has an average net thickness range of 41.49 m to 64.09 m with an average of 52.78 m (Tables 1-4 and Figure 7). The average $Ø_e$ is 0.21 across the three wells while K, S_w and S_h range from 218.10 md to 608.90 md, 58% to 80% and 20% to 42% respectively (Tables 1-3). The hydrocarbon saturation reduces in the NW-SE trend direction. MOS values are more than the ROS values while the MHI value are less than 0.7, hence hydrocarbon production should be expected. BVW plot shows homogeneity of F6 sand in W-2 and at irreducible water saturation (Figure 8) while in W-7 and W-11, F6 sand is heterogeneous and not at irreducible water saturation. Oil column was Down-To (ODT) 3610.50 m in W-7, GOC was at 3421.26 m and Gas column was Down-To (GDT) 3410.50 m in W-2 (Figures 7-10) [12].

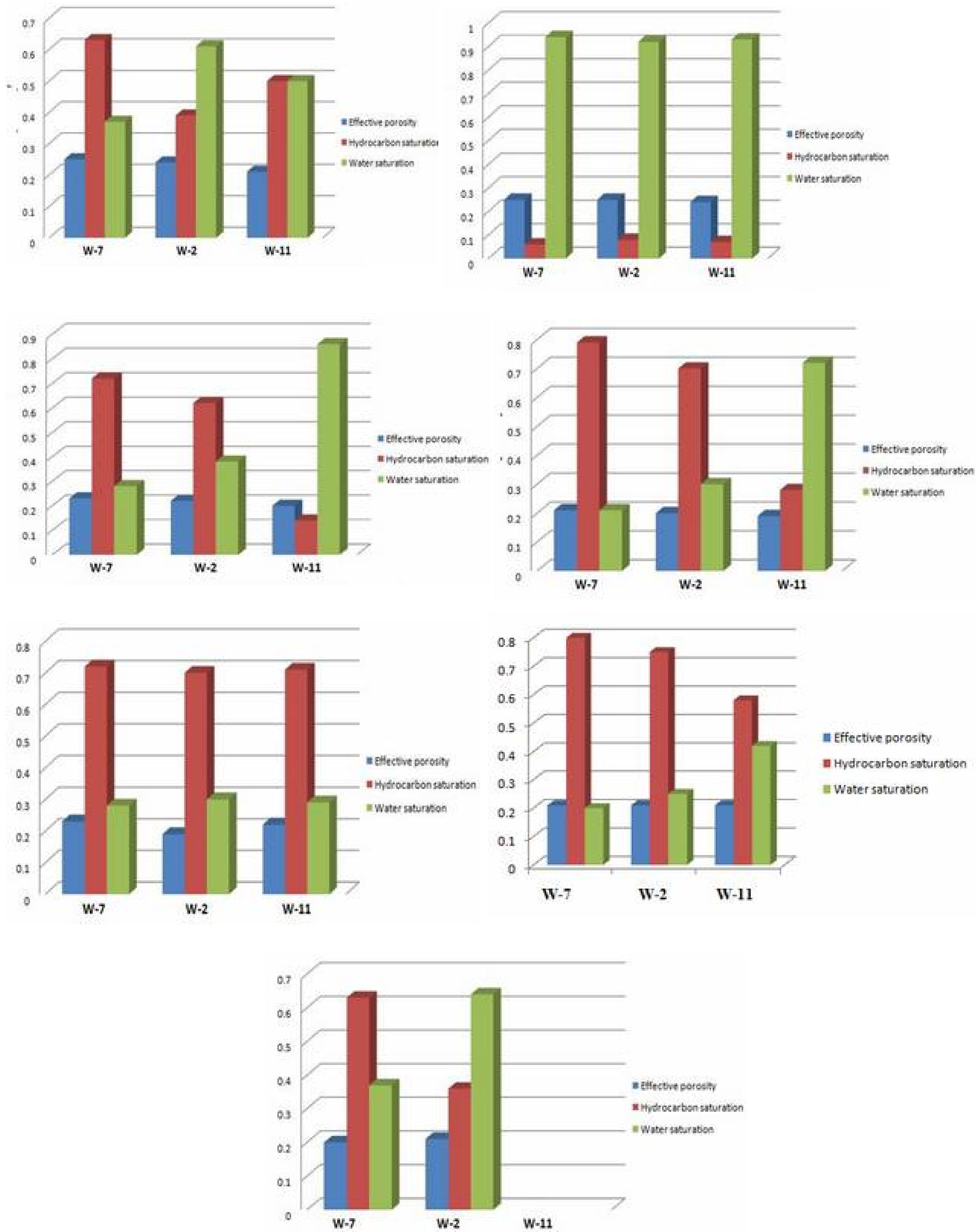


Figure 8. Distribution of $Ø_e$, S_h and S_w values from well logs in the reservoir sands from the wells.

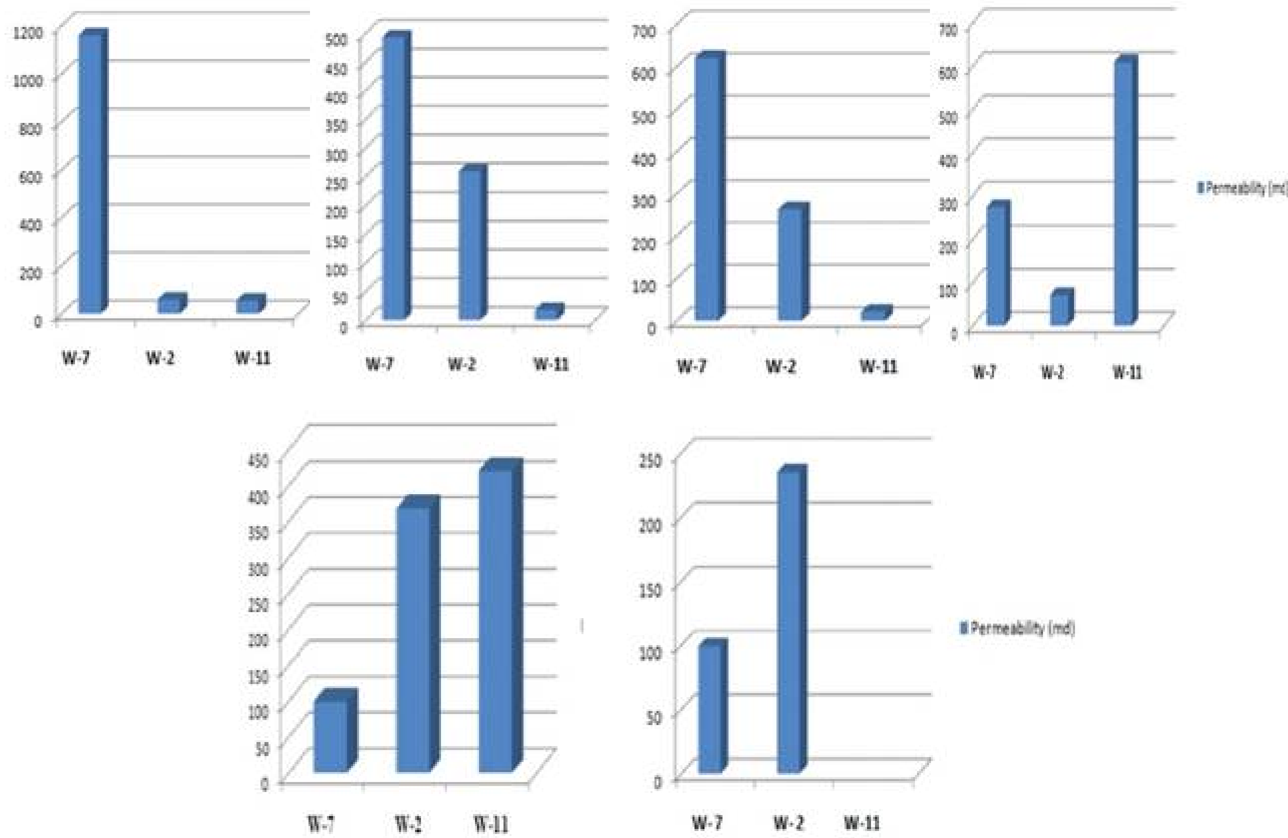


Figure 9. Distribution of permeability values from well logs in the reservoir sands from the wells.

Appraisal of F7 sand body across the studied wells (W-7, W-2, and W-11)

This reservoir sand has net thickness of 52.67 m in W-7 and 64.85 m in W-2 (Tables 1-4 and Figure 7). The F7 sand has good porosity (0.20 for W-7 and 0.21v/v decimal for W-2), K is good to very good (99.31 md in W-7 and 235.3 md in W-2) (Tables 1 and 2). The hydrocarbon saturation reduces in the NW-SW trend direction and varies from 63% in W-7 to 36% in W-2 while S_w value is W-7 is 37% and 64% in W-2. The MOS values are more than the ROS values while the MHI values (0.45 for W-7 and 0.67 for W-2) are less than 0.79 (Tables 1 and 2). Which implies high permeability to oil and oil production should be expected. BVW plots shows that F7 sand in both wells is homogeneous and at irreducible water saturation, therefore water free hydrocarbon is expected to be produced. F7 sand in W-7 is irreducible at 3% while in W-2, it is irreducible at 15% (Figure 9). W-7 has an oil column down to (ODT) 3814 m with a net pay of 38.99 m which is quite good. F7 sand in W-2 is wet (Figures 7-10) [12].

Log facies and depositional environments

The gamma ray log motif was used in interpreting the depositional environment of the sand bodies since they exhibit different shapes which are diagnostic of different depositional environments. The bell shape, funnel shape, cylindrical shape, irregular trend and bow shape were observed in all the wells (W-7, W-2, W-9 and W-11).

The irregular trend is present in all the wells and more prominently in well W-11 at a depth of about 2500 m to 3090 m. The trend has no character, representing aggradation of shales or silts deposited from suspension and show high lateral continuity and low lithological variation. The irregular shape of the gamma ray log was interpreted as basin plain environment [8].

The funnel-shaped successions that characterize the F3, F4 and F5 sands in some of the wells (Figure 10) suggest either crevasses play or prograding marine shelf. Those funnel shapes with greater thickness suggets a prograding marine shelf deposit while those with smaller thickness indicate acrevasse splay which are deposit of deltaic sediments formed after the flooding of the bank which leads to fan-shaped sand deposit on the delta plain [13]. The crevasse splay sand observed is of deltaic/fluvial setting. This characterize the lower Agbada Formation where channels and basin floor fans serve as main reservoirs [14].

The cylindrical-shape successions characterize the

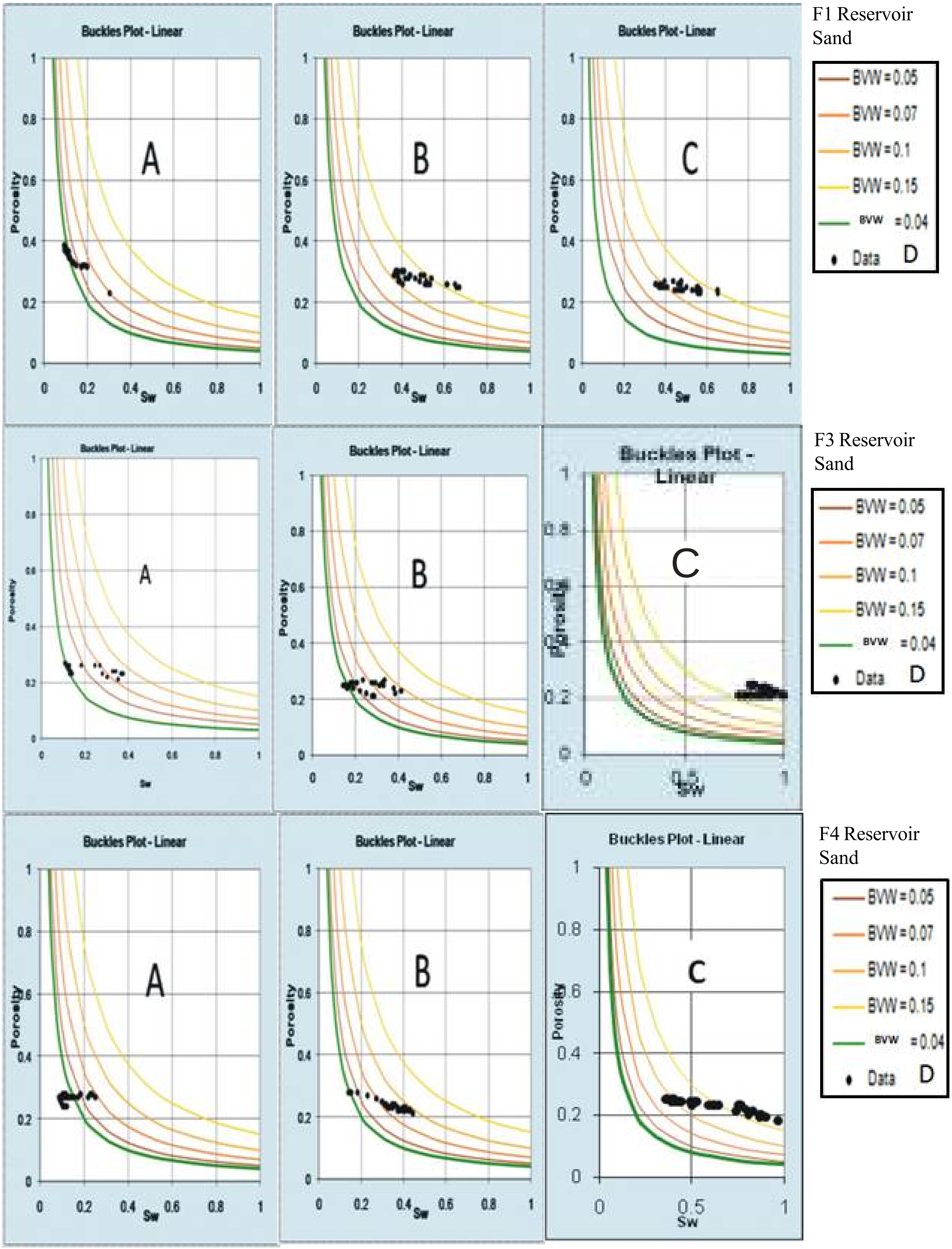


Figure 10a. Bulk volume for reservoir sand bodies in (A) W-7, (B) W-2, (C) W-11 and (D) BVW lines and constant [12].

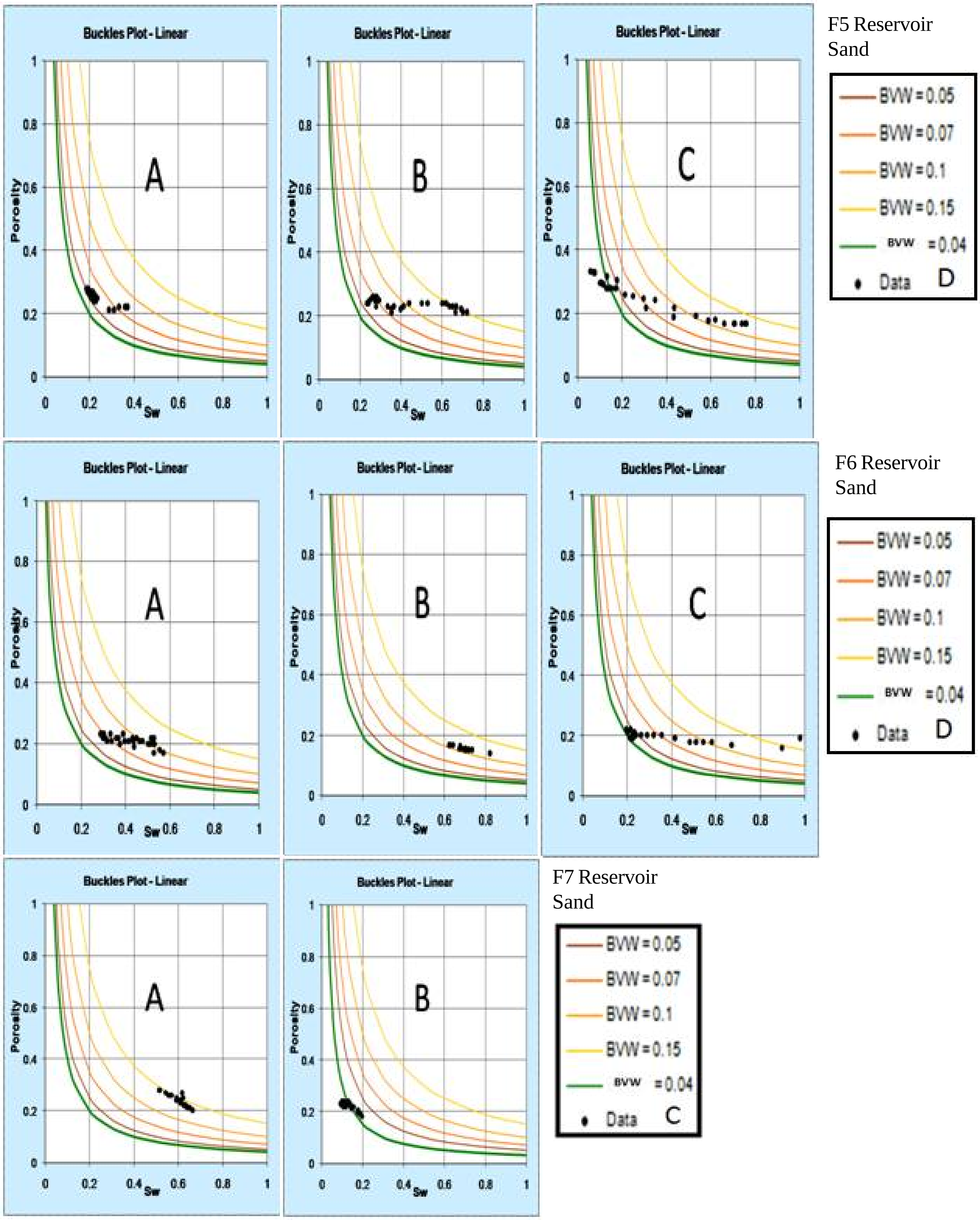


Figure 10b. Bulk volume for reservoirs and bodies in (A) W-7, (B) W-2, (C) W-11 and (D) BVW lines and constant [12].

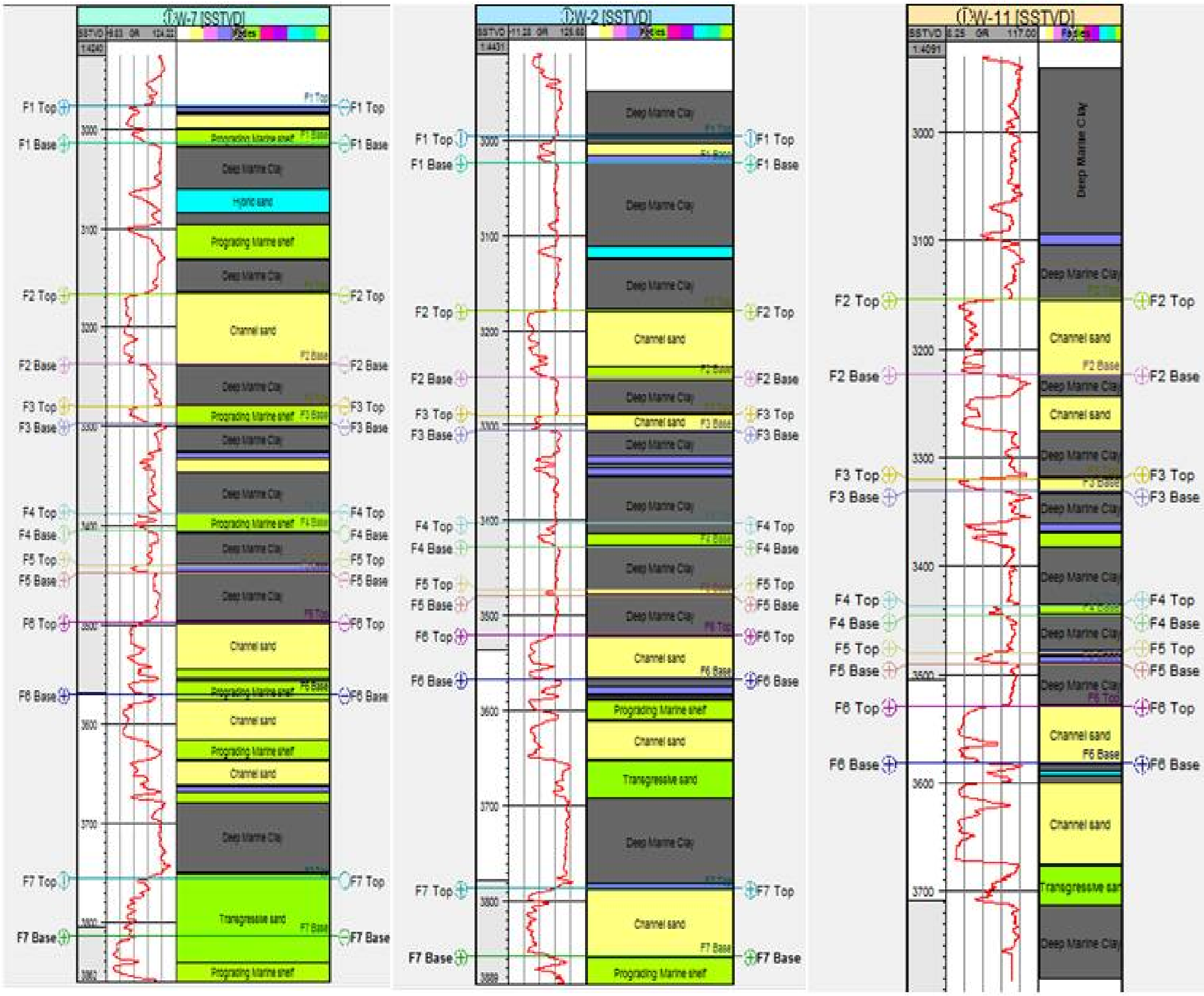


Figure 11. Depositional environments inferred across the wells as interpreted from gamma ray log trends.

gamma ray logs of the F2, F3, F6 and F7 sand bodies in some of the wells. The upper and lower boundaries are sharp and bounded by marine shale (Figure 11). According to Shell Log Shape Classification Scheme, cylinderical-shaped gamma ray logs could indicate a slope channel and inner fan channel environments [15].

The turbidites are deposits from turbulent flow of sediment-laden turbidity current down a slope on the sea-floor. The turbidite sands associated with the wells belong to the upper Akata Formation of the Niger Delta, which is composed of reservoir sands in the deepwater [16, 17]. The slope channel log facies is classified within the deep marine clastic systems [9]. The physical processes, such as tides and waves, which dominate coastal and shallow marine environments, are generally absent or ineffective in the deep marine environment. The Bell-shaped gamma ray logs in the wells were found to have various thicknesses. It occurs in the lower portion of W-7 and form the F7 reservoir sand, likewise in W-2, W-11 and W-9 respectively (Figure 11). The bell-shaped successions are usually suggestive of a transgressive sand, fluvial point bar, tidal point bar, tidal channel or deep tidal channel and fluvial or deltaic channel [8]. The bell-shaped successions were interpreted to be deposited in transgressive marine shelf environment. Most cycles of sedimentation begin with the erosion of underlying sand unit and the deposition of a thin fossiliferous transgressive marine sand [18], however, transgressive marine shelf accumulates the offshore slump deposit which are deposited by global or regional see level changes. Slumps, which are bodies of sediments that have moved under the force of gravity, are also found in river channels and around carbonate reefs.

Water saturation (porosity crossplot)

The crossplot of water saturation against porosity for each of the wells in the field show that the grain size distribuion varies from coarse to fine grained (Figure 12) [19].

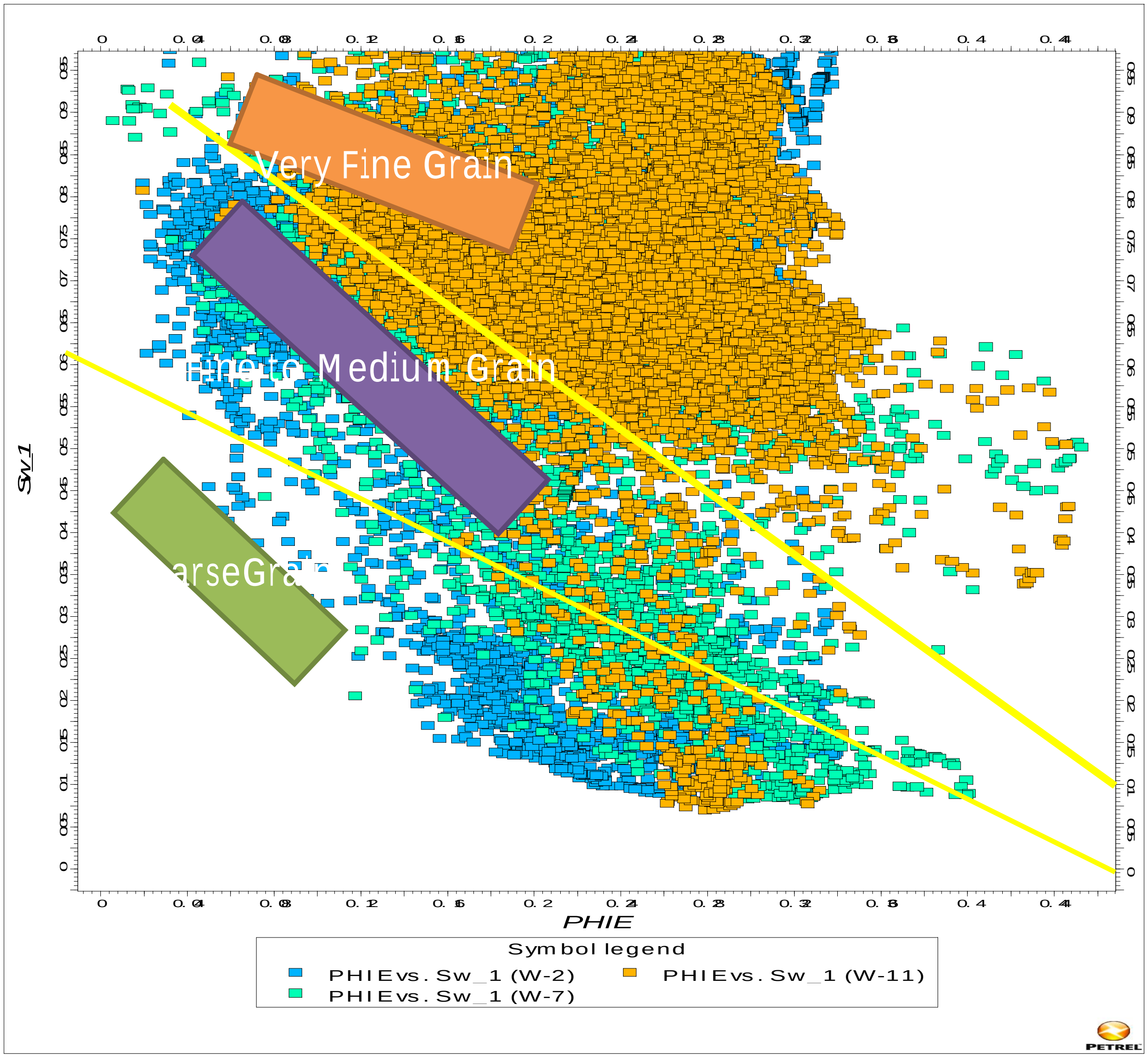


Figure 12. Grain size distribution of the investigated sand in the studied wells [19].

Conclusions

In the petrophysical evaluation of the 'K- Field' via suite of wireline logs, seven sand bodies (F1 to F7) were correlatable, various petrophysical parameters and the weighted arithmetic average for zones were recorded. Hydrocarbon bearing reservoir sand bodies are six (6) in W-7, four (4) in W-2 and two (2) in W-11 wells. The reservoirs are heterogeneous and are not at the zone of irreducible water saturation, except for reservoir sand F3 in W-11, F-6 in W-2 and F7 in both W-7 and W-2 wells. The dominant lithofacies in the wells are sand and shale. The grain size distribution across the wells range from coarse to fine grain with five identified log facies, indicating palaeo-depositional environment of basin plain, crevasse splay, prograding and transgressive marine shelf. The transgressive sands belong to the clastic marine setting while the slope channel and the basin plain belong to the deep-sea setting. However, in the field development and reservoir management, it is pertinent that strategies that utilizes depositional environments, petrophysical parameters and fluid types should be taken into consideration and ensure proper implementation.

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