

Effect of Shale Content on Sand Reservoir Quality: Case Study of Chad Basin, Nigeria

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Abstract: An investigation was carried out on the shale content in sand reservoirs in parts of Chad Basin, Nigeria. This was successfully delineated by estimating the Gamma ray index in a given stratigraphic unit and utilizing the computed value to evaluate the shale volume and porosities of the area. The sand units within the four stratigraphic zones of the basin were evaluated. The depths of high gamma ray counts correspond to high gamma ray index and shale volume. The evaluated shale volumes in the reservoirs were moderate to low and do not vary linearly with depth or well location. The differences in value could have resulted from different depositional processes and faulted areas, which is capable of causing pinch out in the reservoir. The reservoirs in the northeastern wells were observed to be relatively thicker than those in the west and hence it can be inferred that the direction of deposition of sands is east west. However, the reservoirs in the south central contain more shale and will therefore have poor petrophysical properties than the reservoirs in the north east with lower shale volume. The estimated shale volumes, reservoir thickness and porosities in all the wells, however, support hydrocarbon potential in the basin. The net-to-gross sand thickness shows similar consistency in the thickness trend for all the wells.

Key words: Shale volume • Well logs • Reservoir • Porosity • Bornu Basin

INTRODUCTION

The need to find an alternative energy source to those derived in the Niger Delta has driven renewed Government interest in exploring for oil and gas in the Nigerian Chad Basin. The discovery of oil and gas in the neighboring countries of Chad, Sudan and Niger Republics which share the same rift system with Nigeria [1-3], was a motivating factor for this bid. There is also the need to diversify Nigeria's exploration programme in order to increase her oil reserves base [4], which is about 38 billion barrels of oil and 190 trillion standard feet of gas solely derived from the Niger Delta [5].

The Nigerian sector of the Chad Basin, known locally as the Bornu Basin, is one of the Nigeria's inland basins occupying the north-eastern part of the country. It falls between longitudes 9° E and 14° E and latitudes 11° N and 14° N and, covering Bornu State and parts of Jigawa and Yobe States. The basin constitutes about 6.5% of the total area extent of the Chad Basin [6], which is a regional large structural depression common to five countries namely

Cameroon, Central African Republic, Niger, Chad and Nigeria. Its elevation ranges between 200 m and 500 m above the sea level.

Nigerian Government efforts in drilling over 23 exploratory oil wells in the Bornu Basin since 1984 has not result to discovery of hydrocarbon in commercial quantity. The present study is therefore intended to identify possible reservoirs in each Well, evaluate the volume of shale in the reservoirs which has attendant effect on the productivity of the wells in the entire basin. The porosity of the sand reservoirs was also estimated. This is necessary in quantifying the hydrocarbon potentials of the basin.

One of the major problems in accurate formation evaluation is the shale effect in reservoir rocks. Shaliness effects on log responses depend on the shale volume, its physical properties and distribution in the reservoir. Determining the presence of shale within the sand body is very important in evaluating the hydrocarbon potentials of any clastic reservoir. If not recognized in a formation, water saturation will be wrongly estimated which will

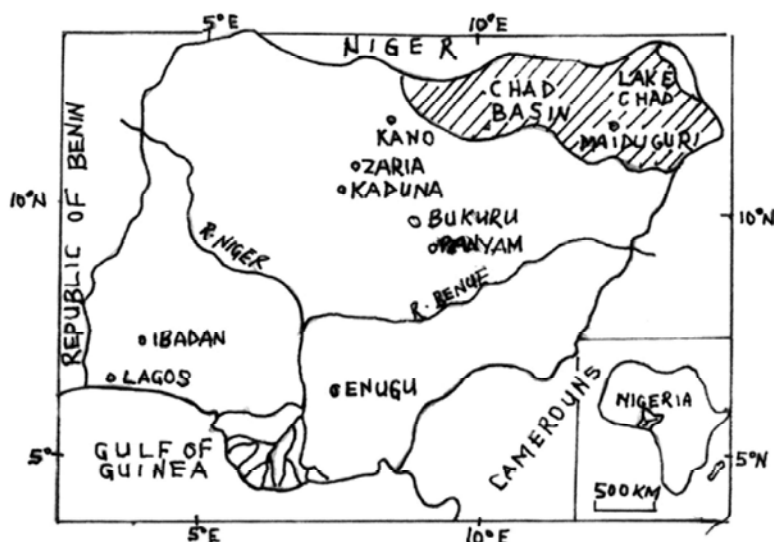


Fig. 1: Map of Nigeria showing location of Bornu Basin.

result in loss of opportunity. Shaliness affects both formation characteristics and logging tool response as it can cause dynamic or static seal within the reservoir, hence increase of shale in sand gives rise to considerable change in formation permeability. Shales are generally conductive and may therefore mask the high resistance characteristic of hydrocarbons [7]. In order to improve production therefore, the determination and identification of permeable zone (shale-free-sand) is necessary.

When Archie's equation which was developed for clean rocks is used on shaly sands analysis, it gives rise to very high water saturation values which may lead to missing potentially hydrocarbon bearing zones. The presence of clay and silt in shaly sands decreases the effective porosity as a result of poorer sorting and increases irreducible water volume when compared with that of sand grain.

[8] evaluated sand-shaliness in parts of the Bornu Basin using six well logs data and observed that the sand-shale ratio was highest in Gabiu-1 and Tuma-1 wells at relatively shallower stratigraphic intervals, which reflects abundant sand content relative to clay component and clearly supports high water energy current. The result reveals the basin to be a hydrocarbon province given that all other hydrocarbon generative indices are in place.

Geology of Chad Basin: The Chad Basin belongs to the African phanerozoic sedimentary basins whose origin is generally attributed to the rift system that developed in the early Cretaceous when the African and South American lithospheric plates separated and the Atlantic opened. Pre-Santonian Cretaceous sediments were

deposited within the rift system [9], while sedimentary sequences were deposited from the Paleozoic to recent, accompanied by a number of stratigraphic gaps.

Bornu Basin (Fig. 1) is a broad sediment-filled depression stranding North Eastern Nigeria, covering Bornu, Yobe and Kano States. [10, 11] have given details on the evolution and framework of the basin. Previous workers [12-14] published information on the aspects of the geology of the Chad Basin. The basin contains about 4,650 km² of marine and continental sediments made up of the Bima Sandstone, Gongila Formation, Fika Shale, Kerri-Kerri and Chad Formations [14]. The source rocks are mainly the Gongila Formation [11-16] and the Fika Shale [17]. Reservoirs are the sandstone facies in the Gongila and Bima Formations.

MATERIALS AND METHODS

Twelve exploratory Well logs data from Bornu Basin were utilized to delineate the petrophysical attributes of shaly-sand reservoirs in the basin (Fig. 2). Four of the Wells, Gaibu-1, Krumta-1, Masu-1 and Wadi-1 were in both LAS and logs format, while others were only printed logs. The logs were selected based on coverage of the explored area and completeness. The Gamma ray logs were used to delineate the sand and shale base lines while the permeable sandy unit intervals for each well were picked using a combination of Gamma ray and Resistivity logs. The Gamma ray log is based on the information that shale presence in a formation increases the Gamma ray log response due to the high concentration of radioactive materials in shale.

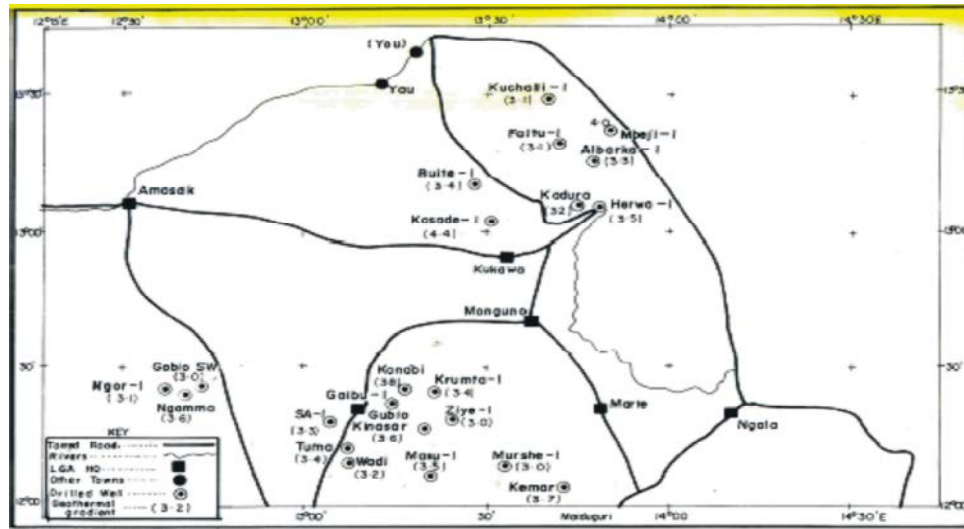


Fig. 2: Location of Wells in Bornu Basin with Inserted Geothermal Gradient Values (Adapted from [18]).

Reservoirs that are free from shale have low concentration of radioactive materials and give low gamma ray readings. The identified sand units were grouped into four sand zones of X1 to X4 based on the depth of the various stratigraphic units in the basin [6]. The four stratigraphic units which are zoned for easy analysis of this work are

Stratigraphic Unit	Depth Range (m)
X1 (Chad Formation)	0 – 800
X2 (Fika/Kerri-Kerri Formation)	800 – 2200
X3 (Gongila Formation)	2200 – 2500
X4 (Bima Formation)	2500 – 5000

In order to reduce the number of data points to analyze, only sand beds range with thickness of up to 10 m and above have been considered. The sand porosity for such range were also computed from the average sonic transit time values using the Wyllie *et al.* (1958) time – average equation:

$$\Phi = \frac{(\Delta t_{log} - \Delta t_{max})}{(\Delta t_{fl} - \Delta t_{max})} \quad (1)$$

where Φ = Formation porosity
 Δt_{max} = Transit time matrix
 Δt_{log} = Transit time from the log
 Δt_{fl} = Transit time of fluid

A Δt_{max} and Δt_{fl} values of 55.5 $\mu s/ft$ and 189 $\mu s/ft$ has been utilized in evaluating the porosity encountered in any stratigraphic unit of the basin.

After delineating the shale and sand formations, it has been observed in practice that the reservoir sands still contain some volume of shale in them. The Gamma ray index option was employed to determine the percentage of shale in the sand lithology (equation 2).

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (2)$$

where I_{GR} is the Gamma ray index, GR_{log} is Gamma ray log reading, GR_{min} is minimum Gamma ray reading in sand bed and GR_{max} is maximum gamma ray reading in shale bed.

With the Gamma ray index known, the shale volume in unconsolidated sand was calculated using the relationship

$$V_{sh} = 0.33(2^{2I_{GR}} - 1) \quad (3)$$

where V_{sh} is percentage volume of shale.

The percentage volume of sand (V_{sand}) was computed by employing the relation:

$$\left. \begin{aligned} V_{sh} + V_{sand} &= 100 \\ \text{or} \\ V_{sand} &= 100 - V_{sh} \end{aligned} \right\} \quad (4)$$

It has been assumed in this qualitative evaluation of shale content that there is no other radioactive minerals other than shale are present. It is noted that formations are regarded as clean, shaly sand or shale zones when V_{SH} is less than 10%; 10 – 30%; and greater than 35% respectively [19, 20].

Other calculations made are the gross sand which is the total thickness of sand in the formation; the net sand thickness which is the portion of sand remaining after removing the shale sequences within the gross sand that tends to divide it into flow units. The net-to-gross sand ratio (NGR) is the ratio of the net sand to the gross sand. It is a measure of the proportion of clean sand within a reservoir unit which reflects the quality of the sands as potential reservoirs. The higher the NGR value, the better the quality of the sand. The sand-shale ratio is the ratio of the net sand to the portion of shale that is removed.

Generally, clay intrusion affects the porosity sonic log. This gives rise to increases in the porosity values obtained in reservoir zones with high sand-shale ratio. Such zones exhibit high hydrocarbon saturation and are referred as zones of interest.

RESULTS AND DISCUSSION

Petrophysical attributes such as reservoir thickness, volume of shale and porosity were delineated in this study. The considered sand beds thicknesses for the Wells vary from 10 to over 300 m and they are separated from each other by shale intervals. The computed parameters are displayed in Tables 1 – 6. The sands are shaly and exhibit good petrophysical attributes with high porosity and reservoir thickness. The porosity decreases with depth. The computed sand-shale ratio and net gross sand were plotted on a bar chart in Figures 3 and 4. The analysis of the Wells used in this study reveals that sand zones X3 and X4 have higher build up with depth. This may have resulted with the growth rate of the fault and sediments deposition into the basin.

Table 1: Derived Sand parameters for Wadi-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1	1	340 – 370	30	0.14	25.74	6.04	0.86	8.5
	2	410 – 440	30	0.13	25.98	6.45	0.87	49.7
	3	600 – 650	50	0.18	41.01	4.56	0.82	56.3
	4	680 – 740	60	0.07	55.89	13.6	0.93	52.6
X2	1	810 – 830	20	0.11	17.76	7.92	0.89	9.3
	2	1340 – 1390	50	0.14	42.9	6.04	0.86	45.2
	3	1460 – 1610	50	0.16	41.91	5.18	0.84	8.9
	4	1910 – 1965	55	0.16	46.32	5.34	0.84	28.4
	5	2000 – 2060	60	0.14	51.75	6.27	0.86	40.9
	6	2145 – 2180	35	0.1	31.51	9.03	0.9	33.9
X3	1	2210 – 2230	20	0.08	18.37	11.27	0.92	26.6
	2	2265 – 2410	145	0.15	123.13	5.63	0.85	25.5
	3	2420 – 2450	30	0.13	26.02	6.53	0.87	16.9
	4	2480 – 2500	20	0.09	18.29	10.71	0.91	17
X4	1	2530 – 2560	30	0.12	26.3	7.12	0.88	21.9
	2	2710 – 2750	40	0.13	34.92	6.87	0.87	0.4
	3	2890 – 2910	20	0.04	19.17	23.13	0.96	-
	4	2915 – 3210	295	0.09	267.56	9.75	0.91	-

Table 2: Derived Sand parameters for Gubio SW-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1	1	320 – 375	55	0.03	53.9	37.99	0.97	1.9
	2	445 – 460	15	0.15	12.82	5.87	0.85	40.8
	3	705 – 720	15	0.1	13.45	8.65	0.9	39.3
X2	1	1165 – 1180	15	0.14	12.86	6.01	0.86	45.3
	2	1785 – 1800	15	0.01	14.91	60.27	0.99	38.6
X3	1	2420-2470	50	0.13	43.43	6.61	0.87	40.8
	1	2650 – 2680	30	0.11	26.69	8.05	0.89	50.6
	2	2765 – 2790	35	0.09	31.79	9.92	0.91	41.6
	3	2800 – 2815	15	0.15	12.77	5.73	0.85	32.6
X4	4	2890 – 2945	55	0.16	46.16	5.22	0.84	48.3
	5	3165 – 3220	55	0.11	49.19	8.47	0.89	46.1
	6	3250 – 3280	50	0.1	44.96	8.92	0.9	42.3

Table 3: Derived Sand parameters for Herwa-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1	1	350 – 385	35	0.03	33.83	28.9	0.97	46.1
	2	410 – 560	50	0.02	49.07	52.65	0.98	10.9
	3	740 – 800	60	0.03	58.46	37.99	0.97	40.1
X2	1	800 – 890	90	0.02	88.62	64.32	0.98	48.3
	2	920 – 950	30	0.03	29.01	29.45	0.97	52.8
	3	1020 – 1080	60	0.03	58.22	32.76	0.97	56.6
	4	1120 – 1470	350	0.05	332.24	18.71	0.95	40.1
	5	1530 – 1560	30	0.04	28.76	23.11	0.96	39.3
	6	1615 – 1625	10	0.1	8.96	8.65	0.9	39.3
	7	2100 – 2130	30	0.11	26.69	8.05	0.89	43.8
X4	1	3340 – 3360	20	0.11	17.77	7.97	0.89	10.9
	2	3420 – 3690	270	0.08	249.64	12.26	0.92	9.4
	3	3750 – 3810	60	0.12	52.76	7.29	0.88	4.1
	4	4050 – 4080	30	0.14	25.89	6.3	0.86	18.4
	5	4230 – 4260	30	0.12	26.53	7.66	0.88	2.6
	6	4620 – 4700	80	0.16	67.14	5.22	0.84	6.4

Table 4: Derived Sand parameters for Mbeji-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1	1	385 – 575	190	0.16	159.6	5.25	0.84	29.6
	2	720 – 800	80	0.13	69.6	6.69	0.87	60.3
	1	800 – 920	120	0.11	106.8	8.09	0.89	42.3
	2	1050 – 1090	40	0.12	35.2	7.33	0.88	47.6
X2	3	1130 – 1490	360	0.09	327.6	10.11	0.91	44.6
	4	1550 – 1610	60	0.13	52.2	6.69	0.87	38.6
	5	2030 – 2060	30	0.14	25.8	6.14	0.86	16.9
X3	1	2315 – 2360	45	0.12	39.6	7.33	0.88	9.4
	2	2420 – 2510	90	0.03	87.3	32.33	0.97	0.4
	1	2600 – 2630	30	0.07	27.9	13.29	0.93	9.4
X4	2	3150 – 3175	25	0.04	24	24	0.96	6.4
	3	3530 – 3555	25	0.03	24.25	32.33	0.97	10.1

Table 5: Derived Sand parameters for Krumta-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1	1	310 – 370	60	0.1	53.95	8.92	0.9	38.9
	2	390 – 410	20	0.1	18.08	9.4	0.9	24.6
	3	430 – 460	30	0.09	27.25	9.92	0.91	40.2
	4	460 – 505	45	0.11	40.03	8.05	0.89	37.4
	5	540 – 575	35	0.09	31.95	10.47	0.91	45.6
	6	580 – 650	30	0.07	65.06	13.16	0.93	44.7
X2	1	1010 – 1040	30	0.05	28.44	18.19	0.95	44.9
	2	1400 – 1415	15	0.09	13.69	10.47	0.91	11.6
	3	1440 – 1520	20	0.06	75.26	15.88	0.94	2.3
	4	2175 – 2185	10	0.07	9.33	13.99	0.93	12.7
X3	1	2405 – 2425	20	0.06	18.74	14.89	0.94	26.8
X4	1	2610 – 2655	45	0.07	42	13.99	0.93	18.8
	2	2695 – 2710	15	0.09	13.63	9.92	0.91	8
	3	2720 – 2740	20	0.1	17.98	8.92	0.9	13
	4	2760 – 2920	160	0.11	143.11	8.47	0.89	8.2

Table 6: Derived Sand parameters for Ziye-1 Well

Sand Zone	Sand Unit	Depth Interval (m)	Gross Sand (m)	Shale Vol (m ³)	Net Sand (m)	Sand-Shale ratio	Net Gross Sand ratio	Porosity (%)
X1		310 – 370	60	0.11	53.37	8.05	0.89	43.1
		450 – 520	70	0.12	61.55	7.29	0.88	40.1
		635 – 670	35	0.08	32.05	10.88	0.92	45.3
X2		1220 – 1230	10	0.01	9.93	87.06	0.99	28.8
		1630 – 1685	55	0.07	51.33	13.99	0.93	12.4
		1720 – 1750	30	0.03	29.16	34.84	0.97	16.9
		1910 – 1970	60	0.06	56.22	14.89	0.94	18.4
X3		2330 – 2360	30	0.06	28.11	14.89	0.94	40.8
X4		2550 – 2660	110	0.03	106.71	32.43	0.97	40.8
		2720 – 2780	60	0.05	56.98	18.84	0.95	11.6
		2840 – 2900	60	0.04	57.32	21.37	0.96	16.1
		2960 – 2990	30	0.03	29.1	32.33	0.97	14.6
		3110 – 3200	90	0.03	87.3	32.33	0.97	6.4

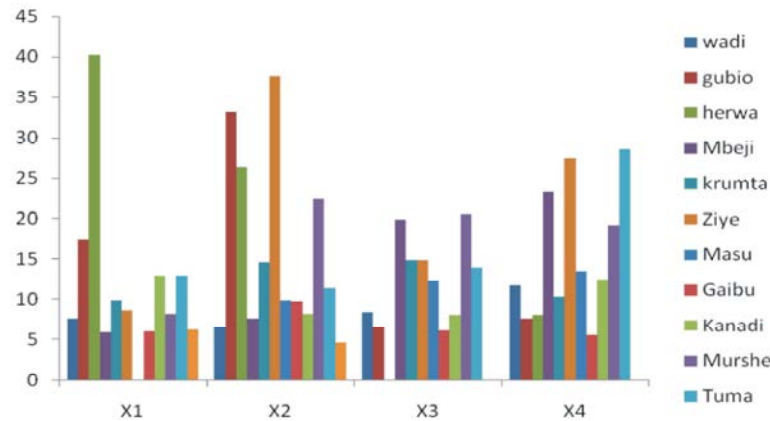


Fig. 3: Sand-Shale ratio for Wells in the Study Area.

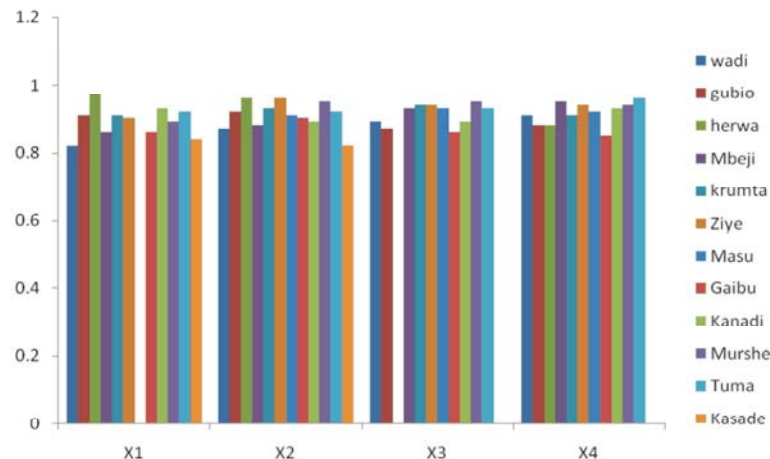


Fig. 4: Net Gross Sand for the Study Area.

Sand thicknesses are relatively higher in Wells located at the northeast than other regions. However, the shale content in reservoir sands for Wells in the southern part of the basin are less, especially in zones 3 and 4 which are

the potential reservoir rocks. Based on this observed sand thicknesses from net gross sand map, it can be inferred that the direction of deposition of the sands go from east (proximal) to the west (distal).

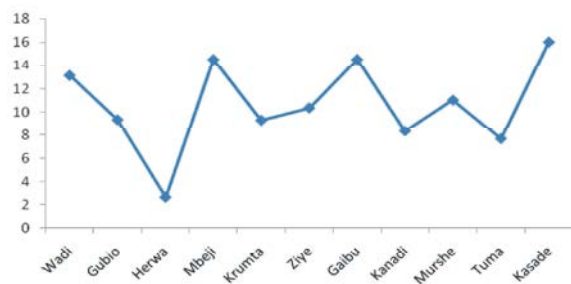


Fig. 5(a):% shale volume in reservoirs of Zone 1

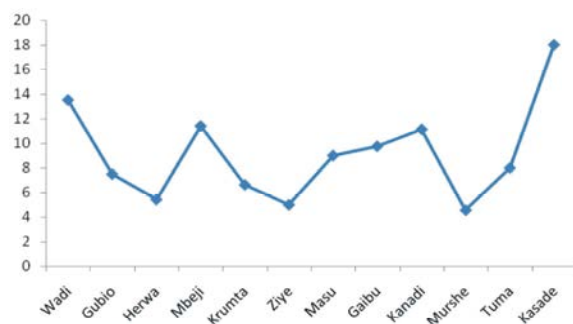


Fig. 5(b):% shale volume in reservoirs of Zone 2



Fig. 5(c):% shale volume in reservoirs of Zone 3

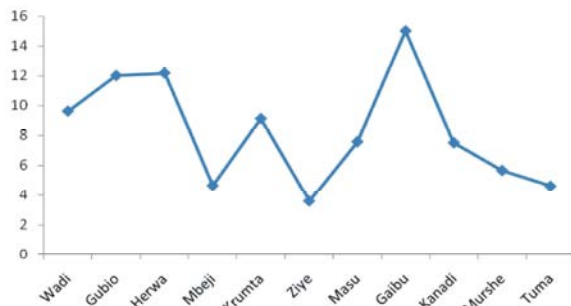


Fig. 5(d):% shale volume in reservoirs of Zone 4

The net to gross sand ratio thickness in Tables 1 – 5 shows a consistent very high thickness in all the wells used for this study. This implies an active depositional

process in the basin that can enhance the accumulation of hydrocarbon. The sand-shale ratio is highest in Herwa-1 and Ziye-1 wells at shallower stratigraphic intervals. These two wells also have a relatively higher porosity values than others. The higher sand content delineated in Herwa-1 and Ziye-1 wells clearly support high energy of deposition by high water energy current. The other wells show moderately low energy of deposition.

The IGR computed for all the wells was observed to be linearly related to shale volume. Figure 5 shows that the percentage volume of shale in the reservoir sand is not linearly related to depth or well location within the basin.

CONCLUSION

This study has successfully estimated the shale volume within the delineated reservoirs in the studied Wells. Reservoirs with high shale volume will have poor petrophysical properties than those with low shale volumes. The delineated shale volumes do not vary with depth or from one region to another. The differences in shale volume within the reservoirs across the basin may have resulted from different depositional processes and faulted areas, which could cause sand formations in some Wells to pinch out. Porosity, which is the basic reservoir quality, is good for all the Wells.

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