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# Structural Characterization and Petrophysical Evaluation of the Aradeiba and Bentiu Reservoirs in Diffra area, Muglad Basin, Sudan

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## ABSTRACT

This study is conducted in Diffra West Oil Field, which is located in 2B OPCO's Block 3 exploratory area, Muglad Rift Basin. Muglad Basin is the largest sedimentary and Oil producing Basin in Sudan. The primary objective of this study is to carry out formation evaluation for hydrocarbon prospectively in Diffra West Oil Field. Petrophysical analysis and 3D seismic interpretation were carried out to investigate the possibility of hydrocarbon accumulation in Aradeiba and Bentiu Formations. Estimated petrophysical parameters were calculated for three wells namely DW-1, HW-1 and SH-1. These parameters include volume of clay, porosity, net pay and water saturation for each well by using interactive petrophysics software (IP v. 3.5). 3D Seismic cube analysis comprised of major and minor faults picking, interpretation of Aradeiba and Bentiu horizons and time to depth conversion using Schlumberger Petrel (v. 2017) software. Petrophysical analysis has shown that the Aradeiba Formation's average clay volume ranged between 1.9% and 23%, its average porosity ranged between 12.7% and 26.6%, and its water saturation (Sw) ranged between 72.5% and 100%, with a total net pay of 23.55 m along the three wells in the study area. Whereas the Bentiu Formation showed average volumes of clay bound between 8% and 19%, average porosity (phi) between 14.8% and 21.2%, and water saturation between 69.5% and 100%, the total net pay in the Bentiu Formation across the study area is about 15.96 m. Seismic analysis and interpretation revealed that the study area consisted of normal major faults, mainly NW-SE trending in line with previous studies in Muglad Basin. Two horizons were picked and mapped, and the results of the depth conversion maps for the Aradeiba and Bentiu surfaces showed structural body dipping to the centre of the structure. Generally, in the Muglad Basin, the Bentiu Formation is considered the main reservoir while the Aradeiba Formation is the secondary reservoir; however, this study has shown that the Aradeiba in the study area has better prospectivity than the Bentiu in terms of average porosity and total net pay.

**Keywords:** Diffra West; Aradeiba; Bentiu; petrophysical evaluation; structural characterization; Muglad basin.

## INTRODUCTION

The breakup of Gondowana in Mesozoic resulted in the formation of West and Central African Shear zone (WCASZ) during Late Jurassic to Early Cretaceous. This occurred due to the separation between African plate and South American plates which resulted in the opening of South Atlantic Ocean. A rift or shear zone propagated into Africa from Nigeria, Cameroon to Central Africa Republic through Chad, Republic of South Sudan and Sudan (Fairhead, 1988). Several rift basins, including those of Sudan, were formed as part of the extensional rift basins along the WCASZ (Fairhead, 1988). Muglad Basin represents part of this Central Rift System. The Basin is oriented NW-SE bounded approximately by the longitudes 26° 00´ and 30° 00´ E and latitudes 8° 00´and 12°00´N, and it occupies an area of about 120,000 km² (200 km width and 800 km in length) as shown in figure (1).

Geophysical studies indicate a sedimentary section up to 13,720 m (45276 ft.) thick in the deepest part of the Muglad Basin, known as the Kaikang Trough. However, the maximum drilled thickness of sediments in the Muglad Basin does not exceed 15,000 ft., which consists mainly of lacustrine and fluvial sediments of Early Cretaceous to Quaternary in age (Schull,1988).

Three rifting stages were developed since the early Cretaceous, the first rift stage was early Cretaceous (Sharif, and Abo-Gabra Formations) approximately 140-95 Ma, the second rift stage was late Cretaceous (Darfur Group which includes Aradeiba, Zarqa, Ghazal and Baraka Formations) approximately between 95-65 Ma, the third rift stage was Paleogene (Nayil and Tendi Formations) approximately between 65-30 Ma). Each cycle boundary is regionally or locally expressed by an angular unconformity. The source rock is lacustrine shale formed in the Early Cretaceous rifting stage. Bentiu Formation is the main oil-bearing unit in the study area, with average thickness of 317 m. The Bentiu Sandstone consists of a series of sandstones interbedded with claystone. Sandstone is medium to coarse grained and less consolidated than the overlying Formations, generally deposited in a braided stream environment with high Rw (RRI, 1991). Aradeiba Formation sandstone is the main secondary reservoirs in the study area, with average thickness about 43 m. The Upper Cretaceous Darfur Group is predominantly composed of claystone and thin interbedded sandstone. Core analysis of Aradeiba sand in Shelungo North_1 shows that the porosity of the Aradeiba E ranges from 21% to 27% averaged 26.2% (Mohammed, 2003). Generally, Aradeiba sands are deposited in lower energy environment (Late Cretaceous (95-65 Ma)) with a much lower Rw. (RRI, 1991). According to Mohammed (2003) the core analysis of Bentiu sandstone in Shelungo North_1 shows that the porosity ranges from 23% to 31.2%, averaged 29.4%. Most studies have been conducted in Muglad Basin generally but, there are less detailed studies have been done in block 3 generally and Diffra West Oil Field specially, hence this study investigates structural and petrophysical complexity for Hydrocarbon accumulation.

## METHODS AND MATERIALS

Petrophysical analysis and wells correlation for three wells (DW-1, HW-1 and SH-1) were conducted by using Interactive Petrophysics (IP. V. 3.5) software, to estimate the Petrophysical parameters such as lithology, clay volume, porosity, water saturation from wireline logs (signature) including Caliper Log (CAL), Gamma-ray Log (GR), Resistivity Logs (LLD, ILD, MSFL), Neutron Log (NPHI), Density Log (RHOB), Sonic log (DT) and Spontaneous potential log (SP). Moreover, 3D Seismic cube was interpreted and structural characterization was done to detect the potentiality hydrocarbons accumulation of Aradeiba and Bentiu formations in Diffra West Oil Field, Muglad Basin, Sudan by using Petrel (2017.4) software.

Dataset and materials used in this study were: Wireline logs (las file), Master logs and a final well reports for three exploratory wells. In addition to Checkshot data for two wells and 3D Seismic section (SEG Y). Several softwars were used including Interactive Petrophysics (V 3.6), Petrel (Schlumberger V. 2017) and Microsoft Excel.

### Petrophysical Evaluation

The classification of wireline logs can be based on either the principles of operations of logging tools or their usage. In this study the classification based on their usage was used: Porosity logs: Sonic (DT), Density (RHOB) and Neutron (NPHI) logs, lithology logs: Gamma-Ray (GR) and Spontaneous Potential (SP) logs and Resistivity logs: Induction (ILD), Laterologs (LLS, LLD), and Micro resistivity (MSFL) logs. The volume of shale was estimated using Single curve indicator (GR) and double curve indicator (Neutron /Density X plot). The method that gave the minimum value of shale volume was chosen for further estimation of porosity and water saturation in order to minimize the influence of reducing reservoir quality caused by a high content of shale volume. Porosity was calculated from density-neutron combination logs. This provides a good source of porosity data, especially information of complex lithology. Better estimates of porosity are possible with this method than using another tool separately such as density and sonic because inferences about lithology and fluid content can be made and it can be calculated mathematically using the following equation (Asquith, and Gibson 1982).

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$$\phi_{N-D} = \left( \frac{\phi_N^2 - \phi_D^2}{2} \right)^{\frac{1}{2}}$$

Ø N−D = Neutron-density porosity,

N φ = Neutron porosity and D φ = Density porosity

Water saturation of uninvaded zone was calculated from both clean Equation and shaly-sand saturation Equations. In this study, Indonesia Equation, were used in Interactive Petrophysics software (IP) to calculate the water saturation of the reservoir rocks as following:

$$\frac{1}{Rt} = \frac{\phi_T^{m^*} \times SwT^n}{a} \times \left( \frac{1}{Rw} + \frac{Swb}{SwT} \left( \frac{1}{Rwb} - \frac{1}{Rw} \right) \right)$$

Vcl = wet clay volume

Rcl = Resistivity of clay,

Sw = effective Water saturation,

Ø = Effective porosity,

Rw = formation Water resistivity,

m = Cementation factor,

n = Saturation exponent

a = tortuosity factor.

Rt = input resistivity curve

The Cut-offs used for volume of clay (V.cl) is 50%, porosity (phi) is 12% and water saturation (Sw) is 70%.

**Seismic Interpretation**

Seismic interpretation, in the context of petroleum exploration, however, should not be limited to only offering the geophysical results but needs to be geologically inclusive to address the exploration problems at hand. In this study systematic interpretation work flow were followed. The essence of seismic interpretation lies in the art of obtaining successful ties of seismic with well log data, specifically for the target objectives (reservoirs). The process is known as seismic or well calibration/tie. In this study, the mis-ties were investigated by shifting of the synthetic seismogram, by a few traces, in the vicinity of the well, therefore desired match were achieved.  A synthetic seismogram tied at the wells, besides giving ideas about positioning of well on ground and kind of reflections expected from the subsurface strata, it shed light on the quality of the processed seismic data. The input data package to work with generally consisted of a coarse grid, this seismic interpreted with two wells control (DW-1 and HW-1). The recording method of seismic reflection data is in the domain of time (mostly in two-way time) (Sismanto a, 1996), whereas the interpretation of seismic data generally demands results using the depth. Therefore, the seismic time to depth conversion is one of the most important parts in the flow of the overall seismic data interpretation. In determining the value of depth, slope, thickness of a reflective plane (reflector) understanding seismic wave velocity is essential (Sheriff, R.E., and L.P. Geldart, 1995). One key aspect in the conversion of seismic data into depth is velocity modelling, which determines the relationship between the depth and the seismic time (TWT) (Etris, E.L. et al., 2001). In this study depth conversion maps were generated for both Aradeiba and Bentiu surfaces by using single function velocity model, by undertaking this process, the structural seismic section was obtained. Thus, the results of the seismic section in the depths were achieved.

**Petrophysical results**

From the basic log analysis, the lithology, hydrocarbon saturation (Sh) and net pay zones were estimated. Basic log Analysis was achieved using these basic logs namely, Caliper (CAL), Gamma (GR), Resistivity (RT), Neutron (NPHI), Density (RHOB) and Sonic (Sonic). The calibration procedures that are used in this study to minimize the errors and uncertainties in the final results, the wells were divided into various (Hydrocarbon) reservoirs, with respect to the lithology, net pay zone, and porosity, bulk volume of water, apparent water resistivity and water saturation. So, from water saturation calculation, it is clear that Indonesian model was the best method used in Aradeiba and Bentiu formations because shale content is relatively higher. Petrophysical parameters (V.sh, Ø and Sw) for three wells were calculated, DW-1, HW-1 and SH–1 respectively. As it is stated earlier Aradeiba and Bentiu Formations were targeted in all the wells in the study area, volume of clay (V.sh) was calculated for targeted zones using single curve indicator (GR) and combined Neutron Density cross plot.

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**The result of DW–1 Well**

Two reservoirs in Aradeiba formation (Are1 & Ar2) were determined from the intervals 2820 m – 2845m and 2890 m– 2988.6 m respectively. While one reservoir interval was identified in Bentiu formation from the interval 2997.9 – 3170.7. The reservoir Ar1 has the highest volume of clay (33%) and some volume of silt while this interval is poorly packaged with sand. Volume of clay in this well is averaged from neutron density cross plot curves, as the result showed, while Aradeiba 2 (Ar2) resulted the lowest average volume of clay (5.5%), moreover, Bentiu (B1) presented as the thickest interval of this well with 30% of N/G ratio and 19% of volume of shale. In this well, average porosity (Neutron/ Density) method was used to calculate the pore space in the three zones, average effective porosity in this well is clearly varying, Aradeiba1 (Ar1) showed the minimum value comparatively with other zones in DW-1 well recording 15.7%, whereas Ar2 and B1 have shown the same value of average porosity 18.2% resembling maximum value recorded in this well. Water saturation was computed using Indonesian equation in all zones, from the result, it is clear that the minimum value of Sw is 69.5 % and a maximum value of 85.7 % at Bentiu1 and Aradeiba1 zones respectively. Reservoir summary showed that Bentiu1 was the highest value in term of gross thickness (118.26m), but in general considering the other reservoir measurement parameters, Aradeiba2 showed the thickest interval of net sand, maximum net/gross values, as well as lowest volume of clay in this well.

Pay summary of this well resulted thickest pay zone at Aradeiba2 estimated by 16.23 m of net pay with approximately 56% of hydrocarbon saturation (Sh), followed by Bentiu1 with 14.33 m of net pay and estimated 50% of hydrocarbon saturation (Sh), Aradeiba1 showed the thinnest net pay with 0.61 m and estimated hydrocarbon saturation (Sh) of 36% as shown in table 1, 2. This well showed 31.17 m of net-pay in total. Oil water contact (OWC) was detected in Bentiu formation at depth 3007m from the final well plot. (Fig 2 - a)

**The result of HW-1 well**

In this well, targeted formations (Aradeiba & Bentiu) have been divided to five zones. Three are within Aradeiba formation Ar1, Ar2 and Ar3, while the other two zones are part of Bentiu formation. Zone Ar1 has the maximum volume of clay, while the minimum value of volume of clay is Ar2. Average Volume of clay in this well is calculated from neutron density cross plot and Gamma-ray curves, as the result showed, Aradeiba 1 (Ar1) has the highest volume of clay (around 23%), Aradeiba 2 (Ar2) resulted lowest value

(9.1%), while Ar3, B1 and B2 have shown 12.8%, 11.6% and 11.9 respectively. Average porosity was calculated using Neutron/Density method in Hamam W1, the pore spaces in the studied reservoir zones, are clearly vary across Aradeiba and Bentiu formations, Aradeiba1 Ar3 has shown the minimum value with (12.7%), whereas Ar2 resulted a maximum average porosity (19.1%) in Hamam W1 well, with other zones recorded 15.8%, 17.5% and 14.8% for zones Ar1, B1 and B2 respectively.

From the table 3, average of water saturation in HW-1 is intensively high, it is clearly that B2 showed high water saturation nearly to 100%, while B1 and Ar3 showed water saturation above 80%, in addition to Ar1 and Ar2 showed relatively lower water saturation (76.2% & 75.2 respectively). Reservoir summary of HW-1 well showed that zone B2 has the thickest interval of gross sand and net sand but at the same time it is fully saturated with water, whereas Ar1 and B1 showed the highest ratio of net to gross in the well. Aradeiba3 (Ar3) has the lowest gross/sand ratio. Pay summary result showed mainly intervals (zones) with the possibility hydrocarbons saturation, after applying petrophysical cut-offs. Aradeiba1, Aradeiba2 and Bentiu 1 have considerable net pay, Aradeiba2 showed thickest net-pay estimated with 3.66m, with 21.1% of average porosity (21.1%), as well as lowest volume of clay. As table 4 shows. Aradeiba2 resulted high hydrocarbon saturation relatively, estimated by 60%, followed by Aradeiba1 with 37.5% and Bentiu1 with 36.5%. Aradeiba3 and Bentiu2 showed 12% and 0.4% of hydrocarbon saturation respectively, otherwise fully saturated with water. Hydrocarbon saturation of this well showed 119.48m as gross interval and about 8.39m of net pay.

**The result of SH-1 well**

In this well, targeted formations were divided to four zones. Two zones are within Aradeiba formation (Ar1 and Ar2), while the other two zones are part of Bentiu formation (B1 & B2).

Aradeiba1 and Bentiu values plotted in sandy range with scattered amount of shale in Ar1, Ar2 a cross the plot, moreover, B2 in presented siltier. Average Volume of clay in this well is calculated from combination of neutron density cross plot and Gamma ray curves, as the result showed in table 5, Aradeiba2 (Ar2) has maximum volume of clay (around 17.1%), whereas Bentiu1 has a minimum average clay volume (8.5).Average porosity was calculated from Neutron/Density method in Shamam-1, the pore spaces in the studied reservoir zones, are clearly varying across Aradeiba and Bentiu formations, Aradeiba2 zone resulted a maximum average porosity (26.6%), whereas Bentiu1 zone has shown a maximum average porosity of

(19.6%), nevertheless, Aradeiba1 and Bentiu2 have showed 20.5%, 21.2% respectively. The result acquired using Indonesian Equation showed complete average water saturation with the same value (100%) in all studied intervals, as the result in all studied zones shows in SH -1. Therefore, no any hydrocarbon saturation intervals were observed. Regarding reservoir intervals, Aradeiba1 showed the greatest thickness of Gross and Net sand with 103 m and 69.19 m respectively, followed by Bentiu2 with Gross sand of 43.74 m and Net sand of 40.08 m, additionally, Aradeiba2 with Gross sand of 24.99 m and Net sand of 22.86 m and Bentiu1 with the Gross sand of 21.03 m and Net sand of 20.12 m resembling the thinnest zone in the well. The output of average volume clay (V.cl) calculation showed various values ranging between 13% – 18%, the minimum value of clay volume was recorded at Bentiu1, while the maximum value of clay was recorded at Aradeiba2. Average effective porosity (Av phi) was generally high in all zones. The maximum average porosity was recorded at Aradeiba2 (26.6%), whereas the minimum average porosity was recorded at Bentiu1 (19.6). There was no hydrocarbon saturation recorded in this well, otherwise SH-1 well is fully saturated with water (wet). No thick shale was observed in SH-1 well to play the vital role of hydrocarbon accumulation; poor oil show was detected from master log which indicating the migration of the hydrocarbon.

The pie chart (Fig 2-b) shows the percentage of petrophysical parameters including water saturation (Sw), Porosity (phi) and volume of clay (V.cl) which calculated for Aradeiba (Sw = 67%, phi = 21%%, V.cl = 12%) and Bentiu (Sw = 62%, phi = 20%, V.cl = 18%) pay zones collectively for each formation independently.

**Seismic interpretation**

**Seismic to well log tie**

Well-seismic ties were applied to allow good data measured in units of depth to be compared to seismic data measured in units of time. Synthetic seismogram was generated by using the vertical seismic profile (VSP) which is in depth domain to match the similar events in seismic which is in time domain for Dw-1, HW-1 and SH-1. Bulk time shift for the generated synthetic seismograms were applied in all studied wells. Seismic-to-well tie for DW-1 well revealed fair to good tie which was however, achieved with a -17 msec time shift. This tie formed the most sensitive stage in the horizon picking, which corresponded to the tops of the sands for interpretation. Seismic-to-well tie was also done for wells HW-1 and SH-1 which showed good ties to the seismic data with time shift of -72 and 53 msec respectively, thereby increasing the confidence in the picked events. The above information was integrated into the seismic section using synthetic seismogram generated from sonic and density logs from Dw-1 and HW-1 wells and check shot data from the same two wells. Whereas SH-1 well Checkshot was shared from HW-1. After well tops were picked on well logs data then tied with seismic and spread through seismic reflectors.

After seismic was tied with wells through generated synthetic seismogram horizontally and vertically, 3D seismic section was realized to its real volume. Vertical seismic section as well as the variance edge attributes were generated (structural attributes) from the seismic around In-lines and X-lines generated enhanced visualization of the fault systems interpretation and the pronounced dip of the faults. Considering structural geometry nine major faults were interpreted (F1, F2 F4 F5, F6, F7, F8, F14, F15) in addition to around 40 minor faults on the basis of abrupt termination of events, distortion of amplitudes around a fault zone and change in the dip of an event. The faults identified were mostly normal faults. These faults generally dip Northeast direction (Basin ward) away from the direction of sediment supply while faults F2 and F14 dip in the north and NW directions. Two reflection events (horizons) were picked on the seismic sections (Aradeiba & Bentiu) across the field as shown in Figure 3.

**Time to Depth Conversion**

As all well tops values in depth domain (well) and simultaneously, these values have equivalent values in time domain (seismic). Single function velocity method was used to generate two-way time map for each Bentiu and Aradeiba horizons.

The main objective of the time to depth conversion is to show hydrocarbon prospects in depth domain across the study area. The depth structure maps derived from the velocity model method showed different results and characteristics in Aradeiba and Bentiu horizons (Fig 4). Depending on closures observed, Bentiu structural depth map showed five hydrocarbon prospects while Aradeiba structural depth map showed three hydrocarbon prospects ranked according to their sizes. The closures lie on the major faults structure which are expected to be sealed to prevent the Hydrocarbon migration. The area of this study is approximately 230 km2 and consists of 2 wells (DW-1 and HW-1) while SH-1 well is far away from the seismic cube. One of the disadvantages of the velocity model is that, uses input data, such as the well velocity, the point, or area whose position is far from the location of the well, tends to have a low accuracy.

**Well Correlation**

The correlation was carried out to determine the continuity and equivalence of lithological units for the sand reservoirs and main marker sealing shales for the wells in the study area. Markers tops were identified base on the tops from master logs, the wells were correlated using the gamma ray, Neutron/Density and deep resistivity logs as an initial quick look to identify the major sandstones units. The architecture of the reservoir is essential in describing the lithology, as well as the flow characteristics of the reservoir. In this paper, the various wells of interest in the sector of the study were correlated: To correct the formation tops and locate them at their proper depths, to establish a reference depth for common base Sand and shale volume, therefore, the real top depths of the reservoirs were determined and tied with seismic section and to evaluate the various petrophysical parameters.

**DISCUSSION**

This study carried out by integrating petrophysical analysis and 3D seismic interpretation to evaluate Aradeiba and Bentiu formations. There are les detailed studies have been done in block 3 generally and Diffra West Oil Field specially, hence this study investigates structural and petrophysical complexity for Hydrocarbon accumulation. Saturation results from Indonesian model revealed that, average values of water saturation for the wells were found to be between 72.5% - 100% in Aradeiba and 69% to 100% in Bentiu, the water saturation indicated that the proportion of void space occupied by water and very low amount of oil, so it can produce high water (high water cut). Subsequently, a cut-off value was applied to the reference parameters with the aim of determining net pay zones. Besides of high-water saturation in these wells, the study showed some pay zones which saturated with hydrocarbons in two wells (DW-1 and HW-1), Aradeiba formation with total net pay of 23.55 m and total net pay of 15.96 m in Bentiu formation, from this hydrocarbon saturation result considering hydrocarbon saturation, Aradeiba formation showed more potentiality of oil than Bentiu. No thick shale was observed in SH-1 well to play the vital role of hydrocarbon accumulation besides; poor oil show was detected from master log which indicating the migration of the hydrocarbon due to lag of seal rock. In addition to Petrophysical analysis and structure depth maps showed that the study area trending in North and north-east direction (Basin word), thus increasing fine grain sediments (shale), Nonetheless, the structural interpretation showed no closure in locations of two of the studied wells (HW-1 and DW-1) besides DW-1 well was drilled on the edge of the closure. The depth maps resulted that, the study area trends from south-west to northern-east (basin-ward) as the figure 4 shows. Results of the structural interpretation of the study area revealed nine regional faults and two horizons mapped within the field.

In line with the hypothesis, this study slightly agrees with previous studies in term of high water cut and faults settings, in term of reservoir quality this study revealed that Aradeiba and Bentiu formations in DW-1 well consist more of volume of clay, decreasing toward HW-1 and SH-1 wells, otherwise, the quality of reservoir increases away from the basin direction. In Diffra West Oil Field, to some extend the findings of this study are different due to very limited studies were conducted. Depending on the previous studies Bentiu Formation in Muglad Basin is a major productive formation while, Aradeiba Formation is a secondary productive formation, but this study revealed reversal result. Structural interpretation was in line with petrophysical analysis which strength the confidence of the results.

Further detailed researches are required to stablish whether Aradeiba formation in Diffra West Field is prior prospect. The results have been carried out in this research, within the limit of the amount and quality of data available. Necessary editing and corrections have been applied to resolve errors related to environment and depth shifting. Very few studies have been conducted within the area, therefore, it is expected that this research will help in future explorations and development to carry out more detailed studies in the field.

## CONCLUSION

This study carried out with aim of formation evaluation and to make better understanding of geology in Diffra west area, by integrating 3D seismic attributes with petrophysics analysis, acquired data included suit of wireline logs, 3 exploratory wells, well reports, master-logs, 3D seismic cube and VSP data. The primary well tops have been modified and corrected initially by correlating the studied wells by using Schlumberger petrel V. 2017, petrophysical analysis was practiced and reservoir quality, porosity and water saturation were estimated. The result of the petrophysical parameters proved that lithology is relatively shalier in DW-1 well than SH-1 well which showed sandier lithology, revealing the quality in this direction has good guilty, considering the same scenario, Effective porosity also increasing from DW-1 through HW-1 and SH-1 as showed highest effective porosity. Indonesian model was used as an effective method in water saturation calculation in sand with shale intercalations as the case in the study area. The result revealed that SH-1 well is fully saturated with water while HW-1 and DW-1 showed less water saturation. Hydrocarbon saturation was showed a positive result as net pay intervals across Aradeiba and Bentiu formations, DW-1

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well showed 31.17 m of net pay, whereas HW-1 has shown 8.39m of net pay. During this study some difficulties have been faced, wireline logs in SH-1 well was missed, the available interval with the log was started from 2120m (MD) with no record for micro-resistivity up to depth 3110m. In addition to the distances between each well from another were quietly long and challenging in correlation process.

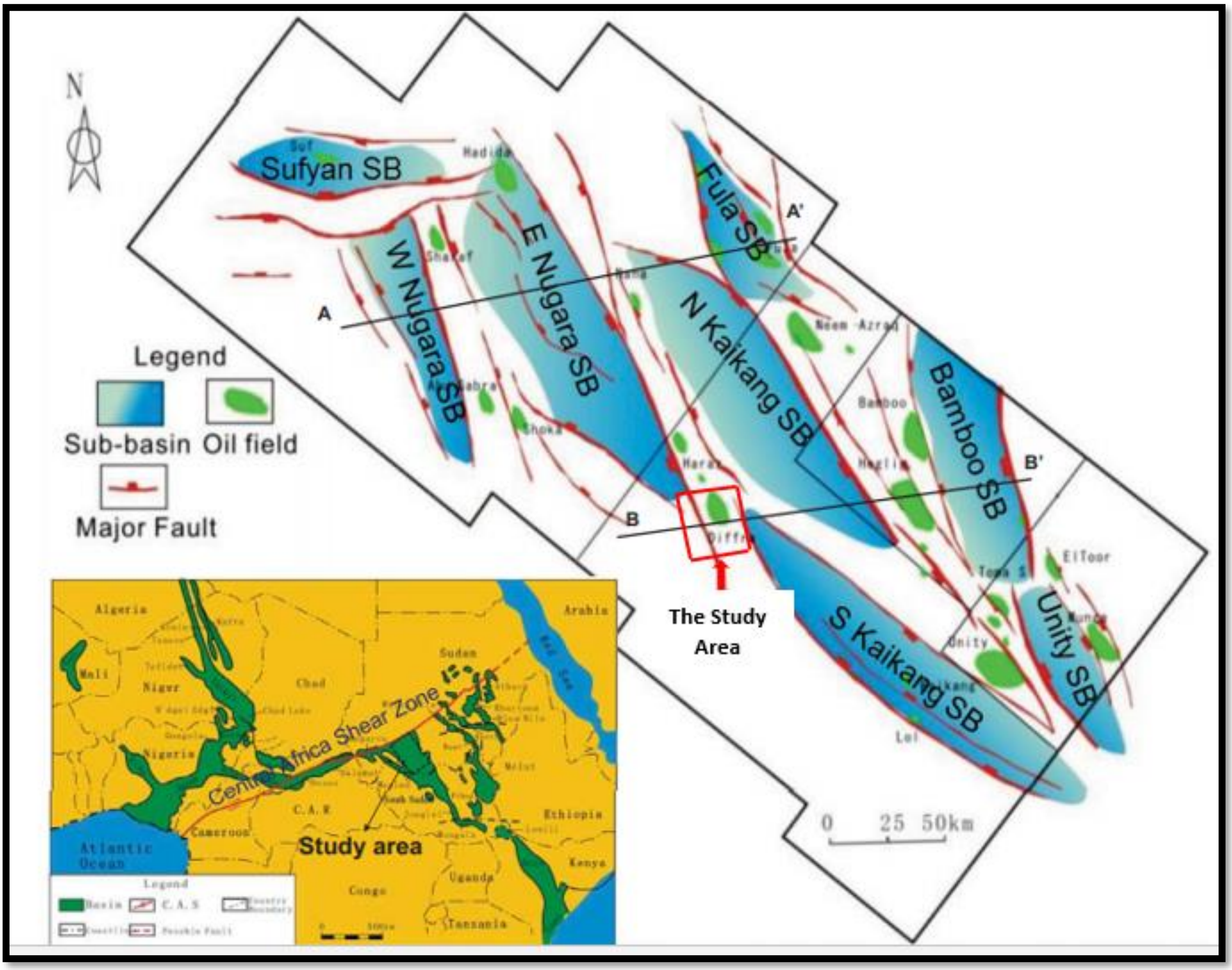


Fig (1) shows the location of the study area (modified after Li Zhi et al, 2017) and the base map of studied wells

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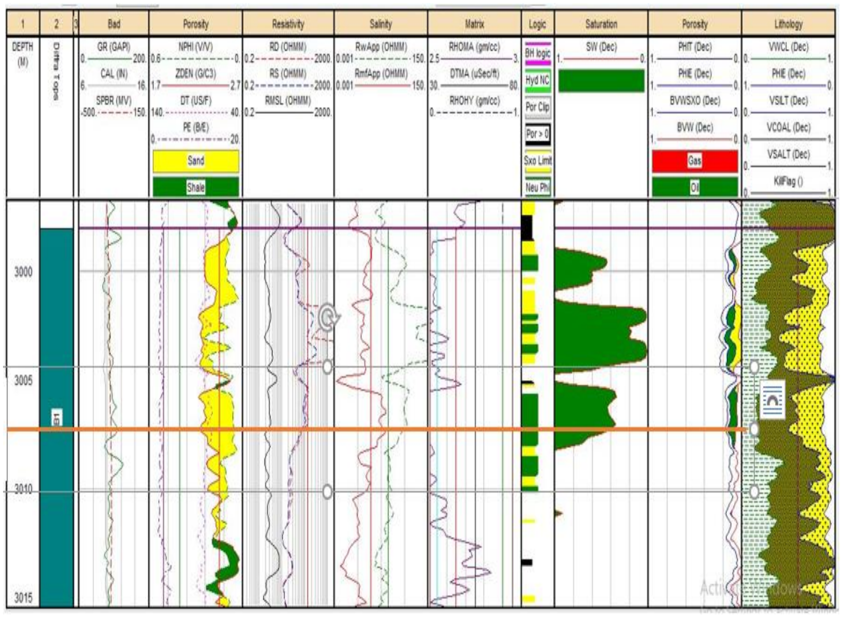
a

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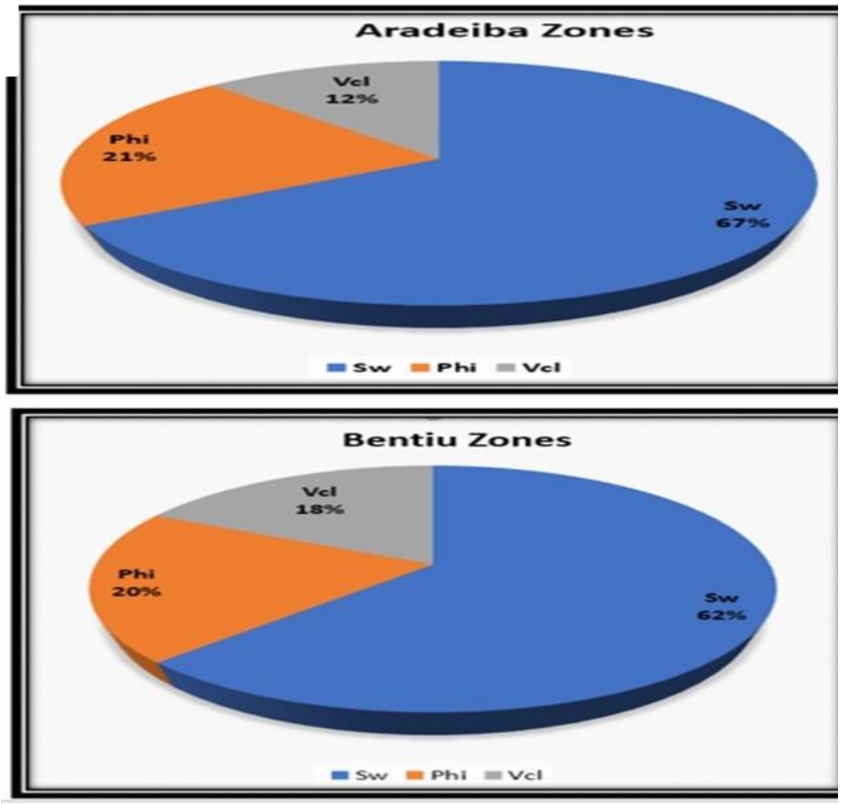


Fig (2) shows oil water contact in DW-1 well (b), and fluids saturation in Aradeiba and Bentiu formations (a),

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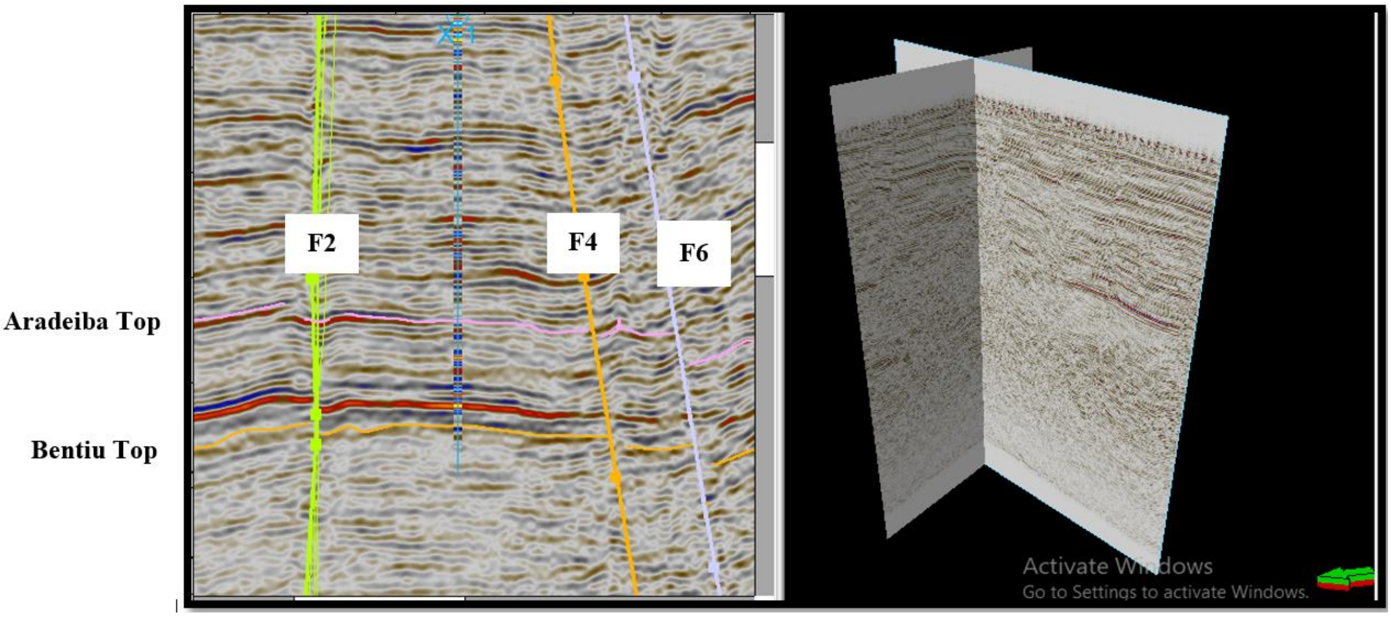


Fig (3) shows faults and horizons on 3D seismic section - Diffra west oil field.

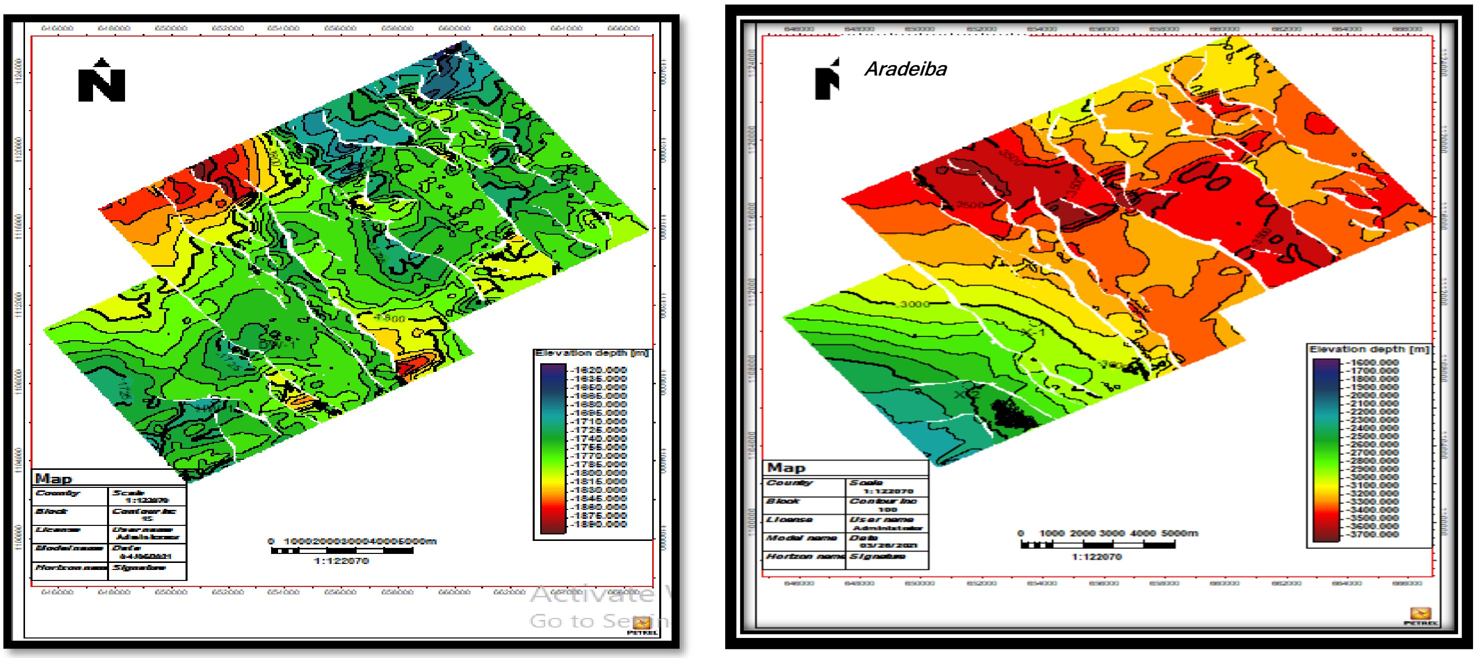


Fig (4) shows Aradeiba and Bentiu depth maps - Diffra west oil field.

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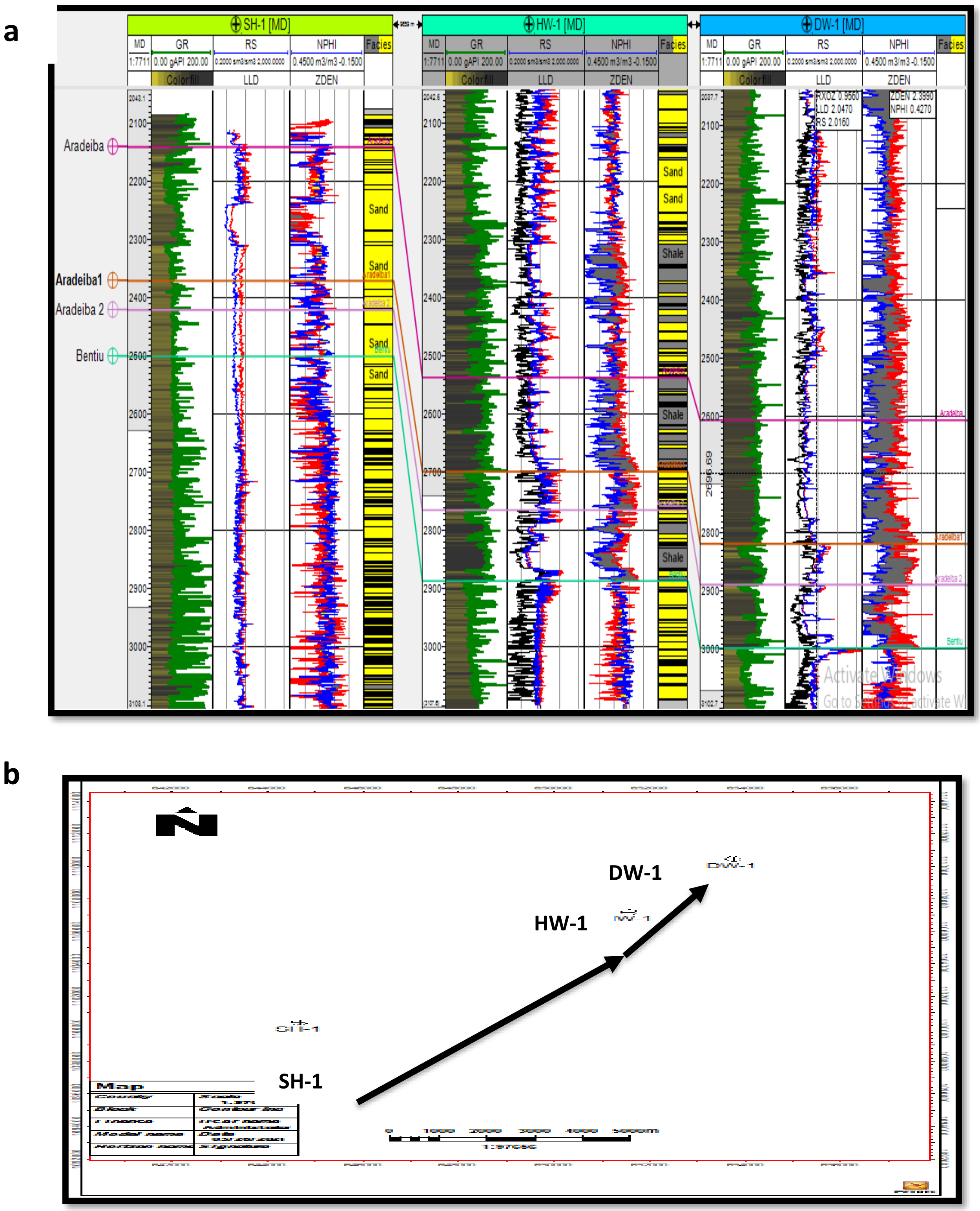


Fig 5 shows the correlated well tops (a) and the direction of the correlation (b).

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**Table 1 shows reservoir summary of DW-1 well**

| Reservoirs (Zones) | Top (m) | Bottom (m) | Gross Sand (m) | Net Sand (m) | N/G (Net/Gross) ratio | Av Phi (%) | Av V.cl (GR & N/D) (%) |
|---|---|---|---|---|---|---|---|
| Ar1 | 2819.9 | 2845 | 25.15 | 1.68 | 0.0351 | 15.7 | 31.9 |
| Ar2 | 2890.27 | 2988.41 | 98.15 | 42.14 | 0.429 | 18.2 | 5.5 |
| B1 | 2998.01 | 3116.28 | 118.26 | 35.81 | 0.303 | 18.2 | 18.7 |

**Table 2 shows net Pay summary in DW-1 well**

| **Reservoirs (Zones)** | **Top (m)** | **Bottom (m)** | **Gross Sand (m)** | **Net pay (m)** | **N/G (Net/Gross) ratio** | **Av Phi (%)** | **Av Sw (%)** | **Av V.cl (GR & N/D) (%)** |
|---|---|---|---|---|---|---|---|---|
| **Ar1** | 2819.9 | 2845 | 25.15 | 0.61 | 0.024 | 17.4 | 64 | 11.1 |
| **Ar2** | 2990.27 | 2988.41 | 98.15 | 16.23 | 0.165 | 19.3 | 44.1 | 0.6 |
| **B1** | 2998.01 | 3116.28 | 118.26 | 14.33 | 0.121 | 20.1 | 49.6 | 15.7 |

**Table 3 shows reservoir summary in HW-1**

| **Reservoirs (Zones)** | **Top (m)** | **Bottom (m)** | **Gross (m)** | **Net Sand (m)** | **N/G (Net/Gross) ratio** | **Av Phi (%)** | **Av Sw (%)** | **Av V.sh (GR & N/D) (%)** |
|---|---|---|---|---|---|---|---|---|
| **Ar1** | 2698.09 | 2709.37 | 11.28 | 7.01 | 0.622 | 15.8 | 76.2 | 23.5 |
| **Ar2** | 2764.38 | 2785.6 | 21.18 | 8.76 | 0.414 | 19.1 | 75.2 | 91 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Ar3** | 2868.02 | 2886 | 17.98 | 0.3 | 0.017 | 12.7 | 88 | 12.8 |
| **B1** | 2886 | 2896.67 | 10.67 | 6.55 | 0.614 | 17.5 | 82.6 | 11.6 |
| **B2** | 2901.54 | 2959.91 | 58.37 | 25.83 | 0.443 | 14.8 | 99.6 | 11.9 |

**Table 4 shows pay summary in HW-1**

| Reservoirs (Zones) | Top (m) | Bottom (m) | Gross Sand (m) | Net pay (m) | N/G (Net/Gross) ratio | Av Phi (%) | Av Sw (%) | Av V.sh (GR & N/D) (%) |
|---|---|---|---|---|---|---|---|---|
| **Ar1** | 2698.09 | 2709.37 | 11.28 | 3.05 | 0.27 | 16.8 | 62.4 | 24.8 |
| **Ar2** | 2764.38 | 2785.6 | 21.18 | 3.66 | 0.173 | 21.1 | 59.6 | 6.2 |
| **Ar3** | 2868.02 | 2886 | 17.98 | 0 | 0 | ---- | --- | --- |
| **B1** | 2886 | 2896.67 | 10.67 | 1.68 | 0.157 | 16.1 | 63.5 | 16.2 |
| **B2** | 2901.54 | 2959.91 | 58.37 | 0 | 0 | --- | --- | --- |

**Table 5 shows reservoir summary of SH-1 well.**

| Reservoirs (Zones) | Top (m) | Bottom (m) | Gross (m) | Net Sand (m) | N/G (Net/Gross) ratio | Av Phi (%) | Av Sw (%) | Av V.sh (GR & N/D) (%) |
|---|---|---|---|---|---|---|---|---|
| **Ar1** | 2135.58 | 2238.91 | 103.33 | 69.19 | 0.67 | 20.5 | 100 | 13.3 |
| **Ar2** | 2284.17 | 2309.16 | 24.99 | 22.86 | 0.915 | 26.6 | 100 | 17.1 |
| **B1** | 2309.16 | 2330.2 | 21.03 | 20.12 | 0.957 | 19.6 | 100 | 8.5 |
| **B2** | 2340.1 | 2383.84 | 43.74 | 40.08 | 0.916 | 21.2 | 100 | 16.8 |

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