Structural and Stratigraphic Reservoir Characterization of "MONI" Field¸ Niger Delta.

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ABSTRACT

Reservoir characterization of "MONI" field of the Niger Delta has been carried out using well log and seismic data. The study is aimed at delineating structural and stratigraphic features associated with hydrocarbon entrapment of the field. Lithostratigraphic correlation reviewed two main lithologies which are reservoir sands and seal shales. Well log correlation and interpretation across the field indicates – main stratigraphic bounding surface which include two sequence boundaries and one maximum flooding surface. This indicates about three depositional sequences exists in the study area. Stacking patterns (progradation, retrogradation, and aggradation) were delineated and interpreted as lowstand system tract (LST), highst and system tract (HST), and transgressive system tract (TST). The alternation of LST, HST and TST offers good reservoir and seal for the hydrocarbon accumulation. The depositional environment of the reservoirs ranges from subaerial channel deposits, barrier bar, tidal channel sands to delta distributary channel fill. Subaerial channel deposits have a bad reservoir quality, tidal channel sands possess a fair reservoir quality while delta distributary channel fill have a good reservoir quality. Petrophysical analysis shows that three reservoirs delineated have a porosity ranging from 19.37% to 23.62%, permeability ranging from 1408.71 to 1855.36 mD, a Net-to-Gross ranging from 0.46 to 0.88, volume of shale ranging from 11.72% to 24.92%, Water saturation ranging from 37.24% to 47.96% and hydrocarbon saturation ranging from 52.04% to 62.76%. Structural interpretation reviewed four main faults that serves as traps to the accumulation of hydrocarbon. Three hydrocarbon bearing sands were interpreted in the seismic volume. Time and depth structure maps show that the hydrocarbon bearing structure is a fault assisted anticlinal structure. Seismic facies analysis reviewed five facies. The study concluded that structural and stratigraphic features can be used to characterize reservoirs.

Keywords: Reservoir characterization, structural features, facies analysis, hydrocarbon entrapment, depositional sequences

INTRODUCTION

Reservoir characterisation and subsurface geological mapping are perhaps the most important tools used to explore for undiscovered hydrocarbons and to develop proven hydrocarbon reserves (Oyedele et al, 2013). Reservoir characterisation is the study of reservoir properties using geologic, geophysical, petrophysical, and engineering disciplines, including uncertainty analysis of geologic and engineering data and spatial variations to describe petroleum deposits and the nature of the rocks that contain hydrocarbon (Lines and Newrick, 2004).

Two important aspects of reservoir characterization are: (1) characterization of the reservoir's geometric

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features, including structural and stratigraphic controls and depositional facies bodies, and (2) characterization of petrophysical properties, including porosity, fluid saturation, and permeability. Stratigraphic reservoir characterization is basically the stratigraphic interpretation of seismic data based on the properties of seismic reflections (Vail, 1987) while the role of structural reservoir characterization in the location and definition of hydrocarbon reservoir is to define the geometry and spatial organization of structures like faults that determines the presence of hydrocarbon, reservoir permeability and reservoir porosity (Cosgrove, 1998; Lines and Newrick, 2004). The characterization of reservoirs requires the integration of different types of data. Seismic data can contribute to a well-defined geometric description of structural and stratigraphic aspects of the reservoir. The result of this study will provide valuable information as regards the reservoir characterization of "Moni" Field structurally and stratigraphically.

GEOLOGY OF THE AREA

The Niger Delta Basin covers an area of about about 300,000km^2 and a sediment volume of about 500,000km^3 and it composed of an overall regressive clastic sequence that reaches a thickness of 9 to 12km (29,500 to 39,400ft) (Hospers, 1965; Kulke, 1995). The Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios (Adiela, 2016; Fig.1). The Akata Formation is the basal unit composed of marine shales believed to be the source rock within the basin. The Agbada Formation is made up of alternating sandstone, siltstone and shale sequences that constitute the petroleum reservoir of the basin. On the other hand, the Benin Formation largely consists of non-marine sands with a few shaly intercalations (Odoh et al., 2012). The basin is bounded to the west and northwest by the western African shield, which terminates at the Benin hinge line and to the east, by the Calabar hinge line. The Anambra basin and Abakaliki anticlinorium mark its northern limit and to the south, it is bounded by the Gulf of Guinea (Oyedele et al., 2013).

From Eocene to Recent, the delta has prograded southward, forming depobelts that represent the most active portion of the delta at each stage of development (Doust and Omatsola, 1990). The Delta has only one identified petroleum system referred to as the Tertiary Niger Delta (Akata – Agbada) petroleum system (Avbovbo, 1978; Kulke, 1995). The Niger Delta province is the twelfth richest in petroleum resources, with 2.2% of the world's discovered oil and 1.4% of the world's discovered gas (Petroconsultants, Inc. 1996a).

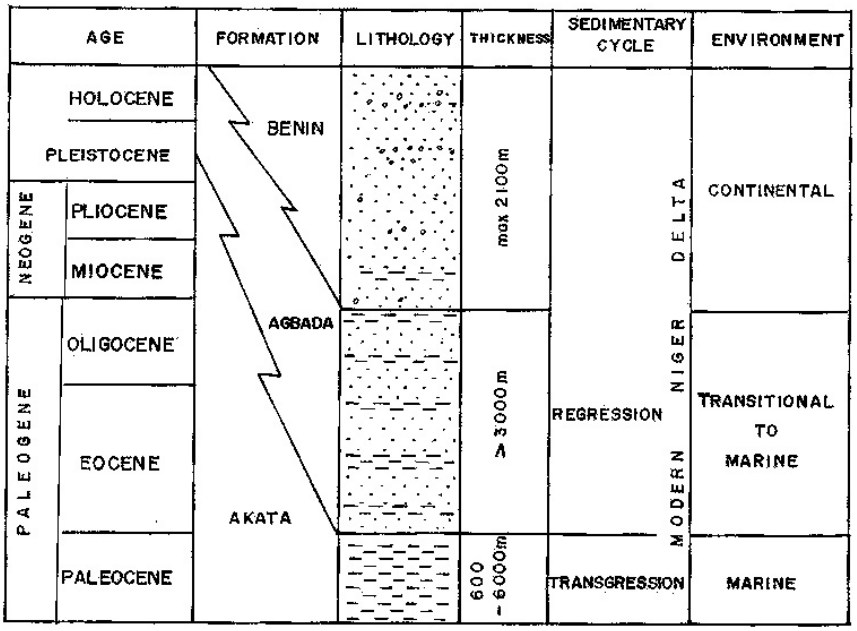

Fig. 1. Generalized Lithostratigraphy of Niger Delta (Nwangwu, 1990).

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METHODOLOGY

The datasets available for this study include 3D Seismic data (Fig.2) and Well Log data which comprises well deviation data for seven wells, Checkshot data for well Moni-7, well logs – Neutron Log, Resistivity Log etc. and well head data for all the wells (Table 1). Interpretation of datasets was done using commercial Petrel software which is an interactive software for well correlation, to estimate all the parameters needed for the petrophysical characterization of reservoirs and other analysis done in the study.

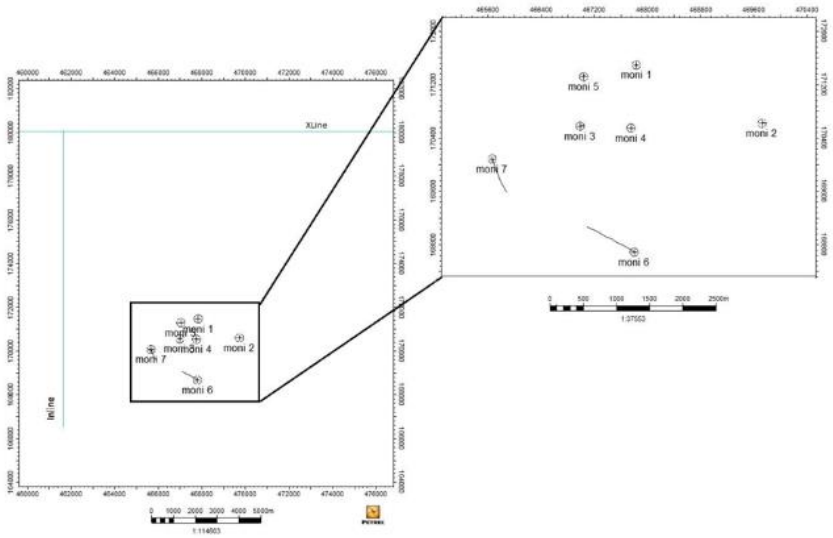

Fig. 2. Base map of the study area showing the location of each well and the seismic lines

Table 1. Available Well Log Data

	DEPTH (ft)	GR (API)	LL9D	FDC	CNL	BCSL	Checkshot	Deviation Data	Well Head
Moni-1	8914	+	+	+	+	–	–	+	+
Moni-2	8511	+	+	+	+	–	–	+	+
Moni-3	8334	+	+	+	+	–	–	+	+
Moni-4	8400	+	–	+	+	–	–	+	+
Moni-5	9011	+	+	+	+	+	–	+	+
Moni-6	8341	+	+	+	+	–	–	+	+
Moni-7	8242	+	+	+	–	+	+	+	+

Where "+" means available and "–" represents not available.

GR – Gamma ray log, LL9D – Resistivity log,

FDC – Density log, CNL – Compensated Neutron log,

BCSL – Sonic log.

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

Well Log Analysis

Correlation of the wells was done both in both N-S and W-E direction (Figure 6 and Figure 7). Three reservoirs were identified and correlated and across the seven wells. The gamma ray log was used to discriminate shale units from sand units. The gamma ray log measures the number of radioactive elements present in a formation. Deflections to the right indicates high radioactivity while deflections to the left indicate lower radioactivity. Resistivity log was used to determine fluid contents and identifying pore fluid types. Density and neutron log crossplot were used to identify the type of hydrocarbon present, while the density and sonic logs were used to generate synthetic seismogram. Wells were correlated and carefully tied to the seismic data using the checkshot data. Horizon/events were mapped, interpreted and correlated all through the study area. Horizon picks were done iteratively in in-line and cross-line directions. Difficulty in picking some of the time domain horizons was encountered due to heterogeneity in the seismic response. This heterogeneity is often present in the form of discontinuous reflection event. The presence of these faults in the study area is an indication that there is a possibility of hydrocarbon accumulation. From the horizon and fault interpretation, time structure maps were produced. Mapped horizons and the generated fault polygons were used to generate depth structural maps for the three reservoirs.

Evaluation of Petrophysical Parameters

Petrophysical evaluation is essential in the oil industry because accurate formation evaluation enables reserve development models for optimal well production and management (Ehinola et al., 2017). The Petrophysical Parameters to be determined includes: Volume of Shale, Porosity, Permeability, water saturation, Net to Gross, Water Saturation and Hydrocarbon Saturation.

- **Shale Volume**

Shale volume is used to evaluate the shale distribution of a reservoir (Islam et al., 2014). The volume of shale is very important to note because it is used to evaluate other petrophysical parameters like reservoir net thickness, irreducible water saturation (Swirr), effective porosity and thus the permeability. The gamma ray index (IGR) was determined from the equation below:

$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$.....(1) (Schlumberger, 1974)

where: I_{GR} = Gamma ray index; GR_{log} = Reading of Gamma ray log; GR_{max} = maximum gamma ray (shale) reading; GR_{min} = minimum gamma ray (clean sand) reading.

$V_{sh} = 0.083(2^{3.7*I_{GR}} - 1.0)$……(2) (Larionov, 1969)

- **Porosity**

Porosity (ϕ) is defined as the pore volume per unit volume of formation or rock. It is also the percentage of the total volume of the rock that is occupied by pores (Asquith and Krygowski, 2004)

The porosity was calculated from density log using

$\emptyset_{tot} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}$……(3) (Dresser, 1979)

$\emptyset_{eff} = \emptyset_{tot} * (1 - Vsh)$……...(4) (Dresser, 1979)

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

where: Φ_{tot} = total porosity; Φ_{eff} = effective porosity, ρ_{ma} is the matrix density = 2.65g/cm^3 (sandstone); ρ_{fl} is the fluid density= 1.0g/cm3 ; ρ_b = formation bulk density.

- **Water Saturation**

Fluid Saturation is the fraction of the formation pores volume occupied by formation Fluid (Adekunle and Elileojor, 2017). In petroleum reservoirs, the fluids are usually water and hydrocarbons. The relative volumes of water and hydrocarbons in the pore volume of the reservoir rock are designated as saturations. Water saturation in the reservoir rock is the fraction of the pore volume occupied by water. Hydrocarbon saturation in the reservoir rock is the fraction of the pore volume occupied by hydrocarbons (Ramesh, 2016).

$Sw = \frac{0.082}{\emptyset_{tot}}$ ..... (5) (Udegbunam and Ndukwe, 1988)

Sh = 1- Sw ..... (6)

- **Permeability**

Permeability (K) is a measure of the ease with which a fluid of given viscosity can flow through a formation (Ologe, 2016).

$F = \frac{0.62}{\emptyset^{2.5}}$ ..... ……..(7)

$Swirr = \sqrt{\frac{F}{2000}}$……..……..(8)

$K = 307 + (26552 * \emptyset^2) - 34540(\emptyset * S_{wi})^2$……(9)

where K is the Permeability, S_{wi} is irreducible water saturation and Φ is effective porosity. Table 2 gives theporosity and permeability values range for characterizing reservoirs.

Table 2. Porosity And Permeability Values for Reservoirs Qualitative Description (Rider, 1986)

Percentage Porosity (%)	Qualitative Description	Average Permeability	Qualitative description
0 – 5	Negligible	<10.5	Poor to Fair
5 – 10	Poor	15-50	Moderate
10 – 20	Good	50-250	Good
20-30	Very Good	250-1000	Very Good
>30	Excellent	>1000	Excellent

- **Net to Gross**

This is a measure of the thickness of the productive (Net) reservoir sands within the Total (Gross) reservoir thickness. The N/G is expressed as a ratio.

NTG= (Net Sand)/(Gross Sand) .....(10)

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

Well Log Lithofacies Identification

The identification of lithofacies and depositional environments from well logs is based on the principle that well log responses are related to changes in the grain size, thickness, texture, and lithology along the well path (Nton and Rotimi, 2016; Abbey and Orenuga, 2017; Fig.3). Shapes on the gamma ray log can be interpreted as grain-size trends and, by sedimentological association as facies successions. A decrease in gamma ray values will indicate an increase in grain size: small grain sizes will correspond to higher gamma ray values.

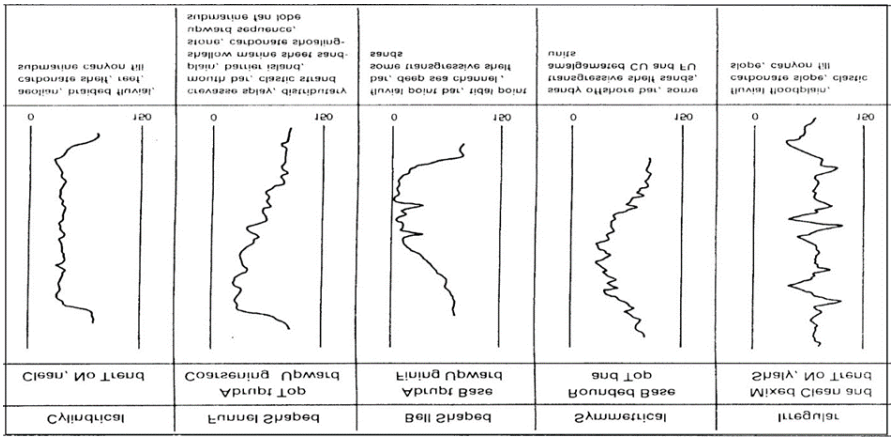

Fig. 3. Idealized Gamma Ray Log Curve Shapes and the Depositional Settings in which they can Originate (Rider, 1999)

Structural Interpretation

Seven faults were picked named F1, F2, F3, F4, F5, F6 and F7. Three horizons were identified. After the horizons were picked, time structure and depth structure maps were reviewed to conduct the structural interpretation of the horizons. A graph of depth (Z) versus the two way travel time (TWT) of the checkshot data (with equation $y = -352.959 + 2.49114x - 0.000715059x^2$) was used to convert the time maps to depth maps.

Seismic Sequence

Seismic Sequences were identified using the reflection pattern of the seismic section as shown in Fig. 4.

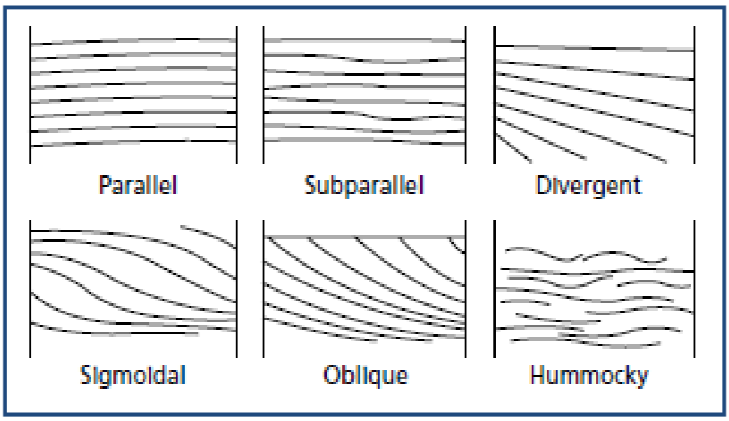

Fig.4: Internal Bedforms that Typifies Different Seismic Sequence within Sedimentary Sequences (Mitchum et al. 1977).

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

RESULTS AND DISCUSSION

Well Correlation

The three reservoirs delineated as R1, R2 and R3 (Figs. 5 and 6). From the well log correlation, it was found that in well Moni-7, all the reservoirs have a low resistivity reading which is suggestive of absence of hydrocarbon in well Moni-7.

Reservoir R1 is shallowest in well Moni-6 where it occurs between depth 7887ft to 7970ft (thickness of 83ft) and deepest in well Moni-1 between depth 7143ft to 7887ft (thickness of 744ft). Reservoir R1 contains both oil and gas but has a low amount of sand compared to other reservoirs.

Reservoir R2 is shallowest in well Moni-7 where it occurs between depth 7028ft to 7309ft (thickness of 281ft) and deepest in well Moni-6 between depth 6977ft to 7415ft (thickness of 438ft). The reservoir contains mostly oil in all the wells.

Reservoir R3 is shallowest in well Moni-5 where it occurs between depth 6018ft to 6510ft (thickness of 492ft) and deepest in well Moni-6 between depth 6261ft to 6846ft (thickness of 585ft). In well Moni-5 and well Moni-6 the reservoir contains only oil but in well Moni-2 the neutron-density crossplot shows the presence of gas while the well log for wells Moni-3, Moni-4 and Moni-3 did not provide the neutron-density crossplot for the top of the the reservoir.

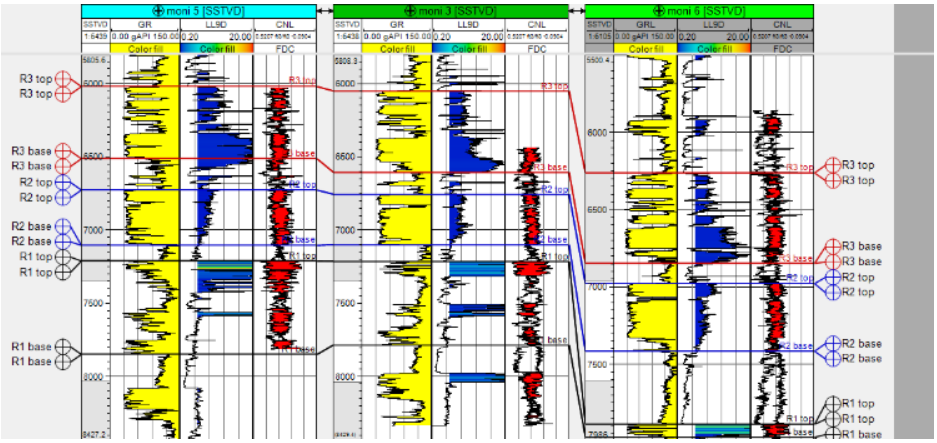

Figure 5: Reservoir correlation across well 5, well 3 and well 6

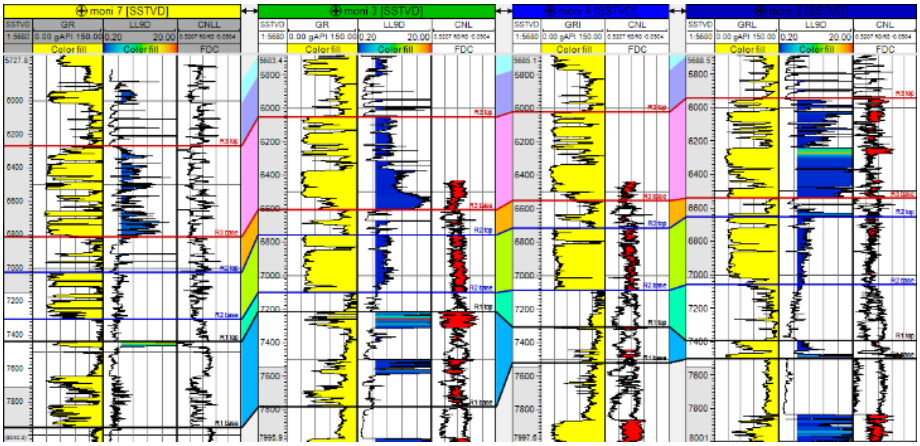

Figure 6: Reservoir correlation across well 7, well 3, well 4 and well 2

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

Petrophysical Evaluation

The values of the petrophysical parameters for all the reservoirs are given in Table 3. Table 4 gives the average values for the three reservoirs. The average porosity ranges from 19.20 to 23.60 which are in the range of Good to Very good reservoirs according to Rider (1986) classification (Table 4). The average Net-to-Gross varies between 0.46-0.88, the average effective porosity varies between 15.96 – 21.98, the average water saturation varies between 37.24 – 48.26 and the average hydrocarbon saturation varies between 51.74% and 62.76%. The permeability is very high ranging from 1408.71-1855.36 milli-darcy. Using the classification of Rider (1986), the reservoirs have an excellent permeability.

Table 3. Computed Petropysical Parameters

Well	Reservoir	Top	Bottom	Thickness	NTG	Vsh	Por	Eff. Por	K	Sw	Sh
1	R1	7143	7887	744	0.53	17.36	21.63	18.3	1652.2	42.96	57.04
	R2	6680	7042	362	0.95	8.97	22.24	20.51	1663.2	39.73	60.27
	R3	5989	6494	505	0.74	11.85	23.37	20.96	1832.1	38.17	61.83
2	R1	7393	7502	109	0.78	19.61	16.83	13.87	1096.7	52.07	47.9
	R2	6652	7058	406	0.84	8.61	25.29	23.35	2033.8	33.5	66.5
	R3	5944	6541	579	0.64	12.2	26.13	23.47	2202.5	33.43	66.57
3	R1	7214	7784	570	0.28	22.88	19.14	15.16	1441.9	52.2	47.8
	R2	6756	7100	344	0.92	10.34	20.99	19.11	1511.1	41.42	58.58
	R3	6051	6606	555	0.7	11.68	24.19	22.9	1859.3	34.18	65.82
4	R1	7307	7522	215	0.1	47.46	15.41	8.52	999.78	58.21	41.79
	R2	6717	7088	371	0.95	11.63	21.97	19.91	1626.1	39.42	60.58
	R3	6026	6561	535	0.75	15.45	24.33	23.68	1883.9	34.1	65.9
5	R1	7209	7846	637	0.42	17.73	21.33	17.9	1609.3	42.76	57.24
	R2	6726	7104	378	0.96	8.02	22.3	20.66	1657.8	39.15	60.85
	R3	6018	6510	492	0.72	10.8	21.85	19.9	1638.2	40.77	59.23
6	R1	7887	7970	83	0.65	24.81	19.12	14.66	1346.2	46.7	53.3
	R2	6977	7415	438	0.82	14.22	22.72	19.82	1729.7	38.25	61.75
	R3	6261	6846	585	0.67	16.23	22.34	18.96	1703.1	39.7	60.3
7	R1	7437	7952	515	0.43	24.6	22.14	17.51	1710.8	40.8	59.2
	R2	7028	7309	281	0.7	20.24	23.7	19.47	1885	37.81	62.19
	R3	6269	6812	543	0.65	19.95	23.16	19.09	1868.5	40.96	59.04

Table 4. Average Computed Petropysical Parameters for Well the Reservoirs

Reservoir	NTG	Vsh	Por	Eff. Por	K	Sw	Sh
R1	0.46	24.92	19.37	15.96	1408.71	47.96	52.04
R2	0.88	11.72	22.74	20.4	1729.25	38.47	61.53
R3	0.7	14.02	23.62	21.28	1855.36	37.24	62.76

Structural Analysis

- **Fault Interpretation**

Fig.7 – Fig. 10 show the seven faults that were picked namely F1, F2, F3, F4, F5, F6 and F7. F1 extends through the map east to west. Faults F1, F2, F4 and F5 are major faults while Faults F3, F5 and F6 are minor faults

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

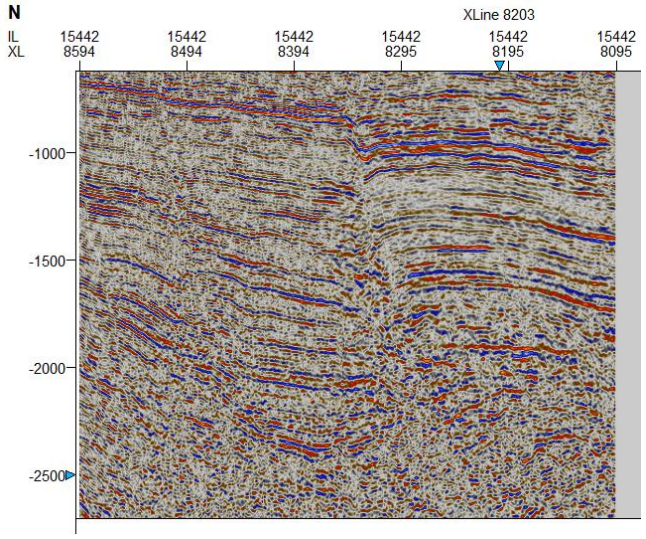

Fig. 7. Raw seismic Cross line 8203 section

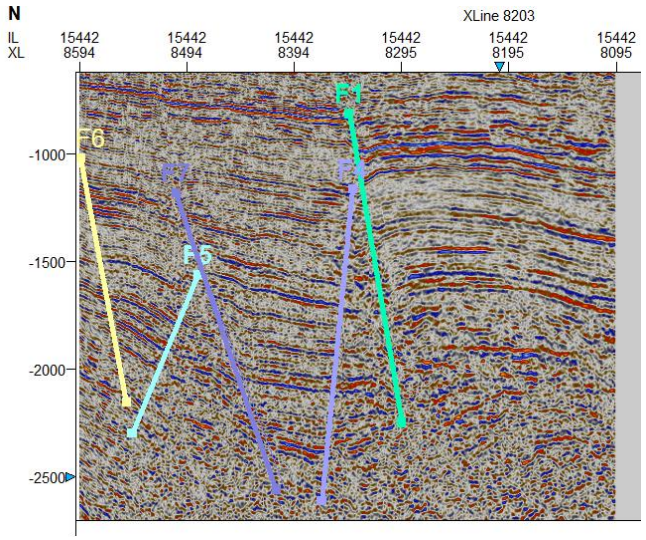

Fig.8. Seismic Cross line 8203 Section Showing Faults F1, F5, F6 and F7

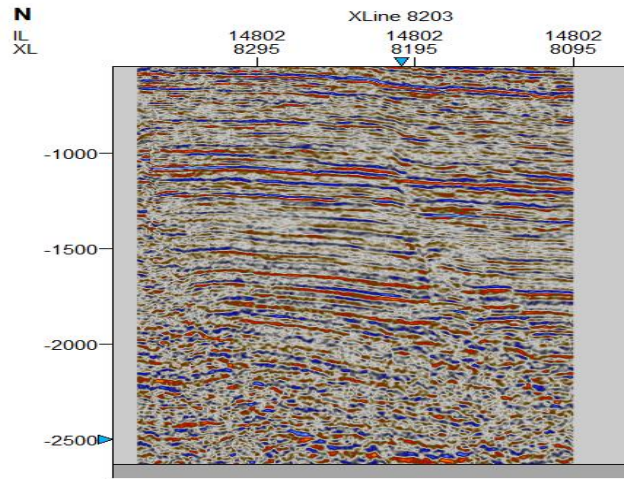

Fig.9. Raw Seismic Cross line 8203 Section

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

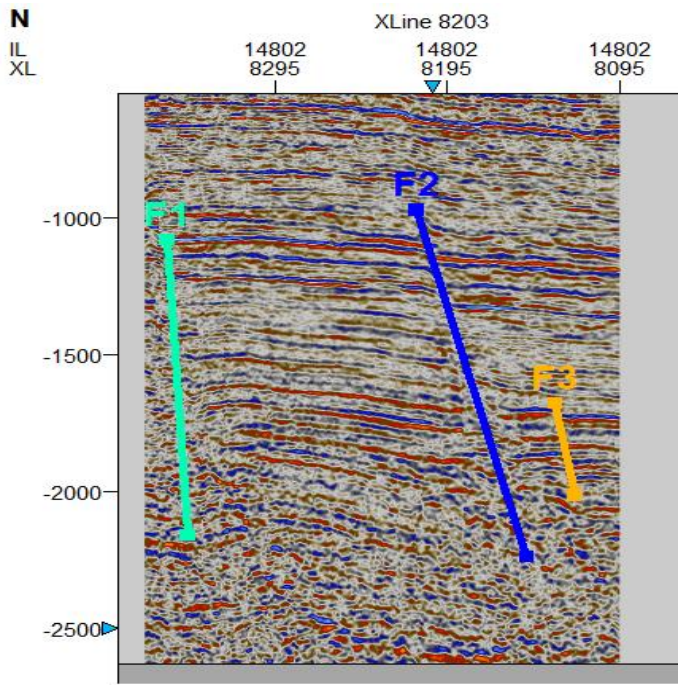

Fig. 10: Seismic Cross line 8203 Section showing Faults F1, F2 and F3

- **Seismic to Well Tie**

Fig.11 shows the synthetic seismograph that was generated using the check shot data, sonic log and the density to tie well Moni-7 to seismic.

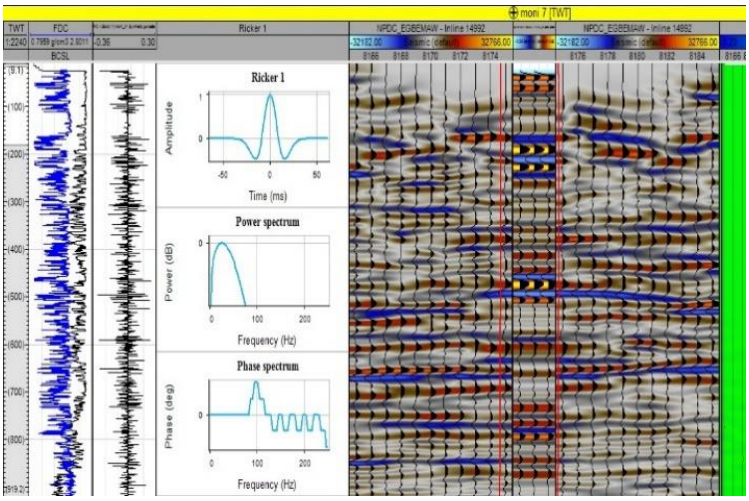

Fig.11.Synthetic seismograph of well 7, generated using check shot data.

- **Depth Maps**

Fig. 12 to Fig. 14 shows the depth structure contour maps for the time structure maps. The colour ranges from red to purple, where red colouration represents places with lower elevation depth and ranges to purple colouration which represent places with higher elevation depth. All the maps are dipping from the North-East direction (lower elevation depth red colouration) to the South-Western direction (higher elevation depth blue to purple colouration) but an anticline structure is present in the southern part of map for Horizon R1 and R2 where the wells are located.

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

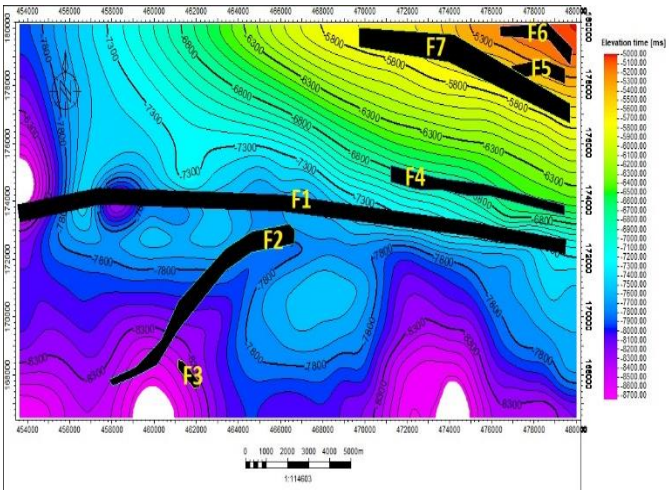

Fig. 12. Depth map for Horizon R1

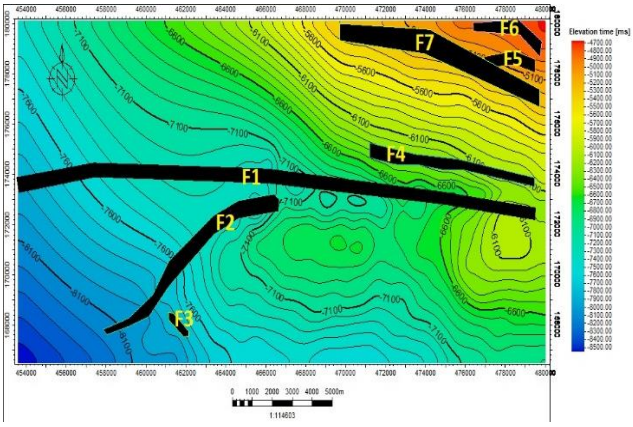

Fig. 13. Depth map for Horizon R2

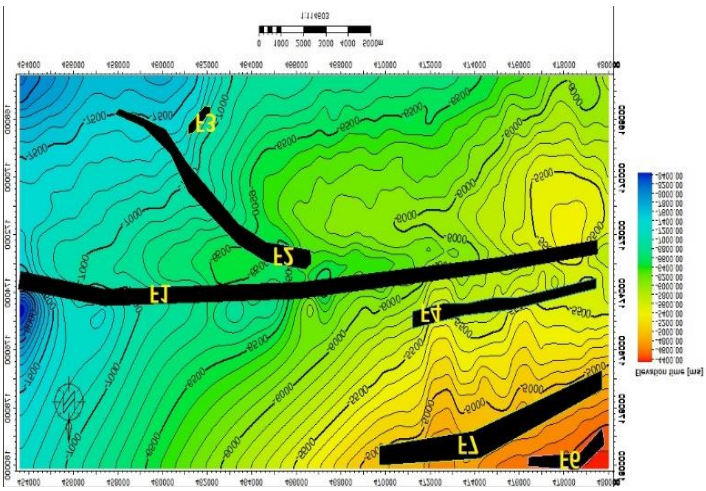

Fig.14. Depth map for Horizon R3

Sequence Stratigraphy

Facies Analysis From Log

From the well log Facies analysis it is found that Reservoir R1 is a Subaerial Channel Deposit (Fig. 15),

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

Reservoir R2 is a Delta Distributary Channel Fill deposit except in well Moni-7 where it is a Tidal Chanel (TC) deposit (Fig. 16). Reservoir R3 is a Delta Distributary Channel Fill (DDCF) and Tidal Channel Deposit (Fig. 17). Two sequence boundaries and one maximum Flooding Surface was identified (Fig. 18). Subaerial channel deposits are known as bad hydrocarbon reseervoirs, reservoir R1 which is a subaerial channel reservoir have an hydrocarbon saturation as low as 41.70% in well Moni-4.

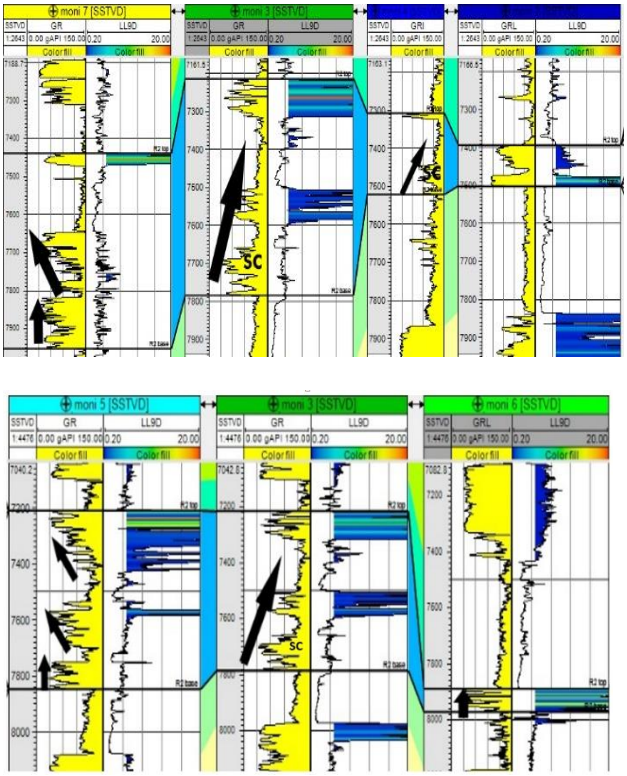

Fig. 15. Depositional Environment for Reservoir R1

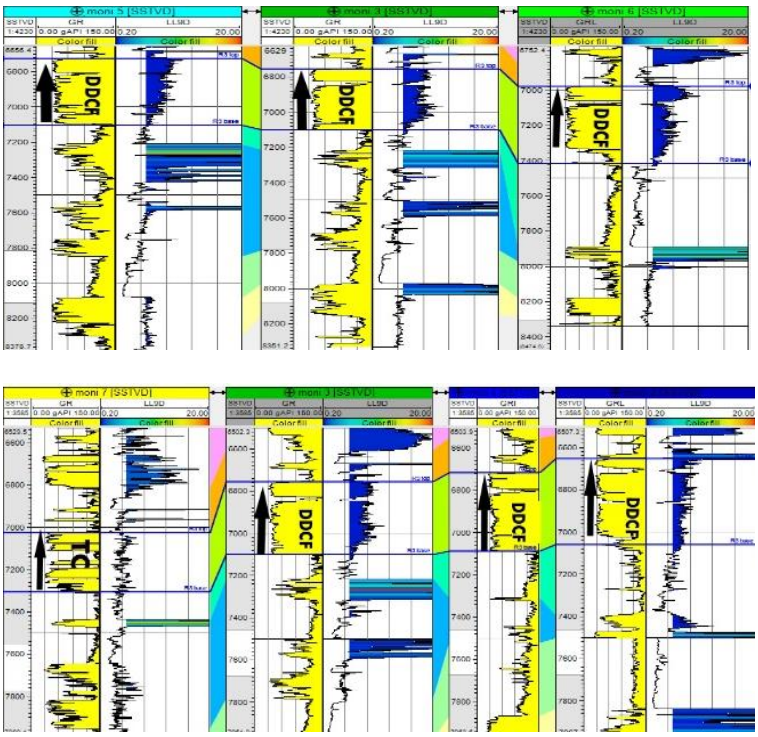

Fig.16. Depositional Environment for Reservoir R2

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

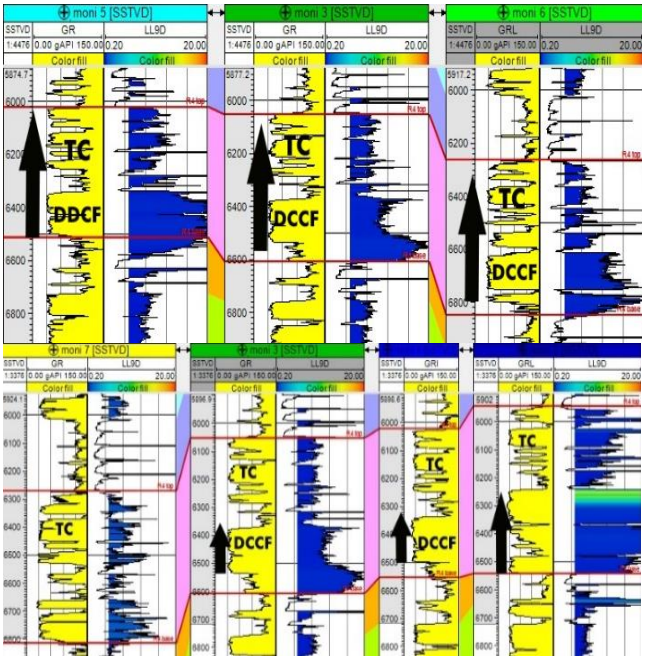

Fig. 17. Depositional Environment for Reservoir R3

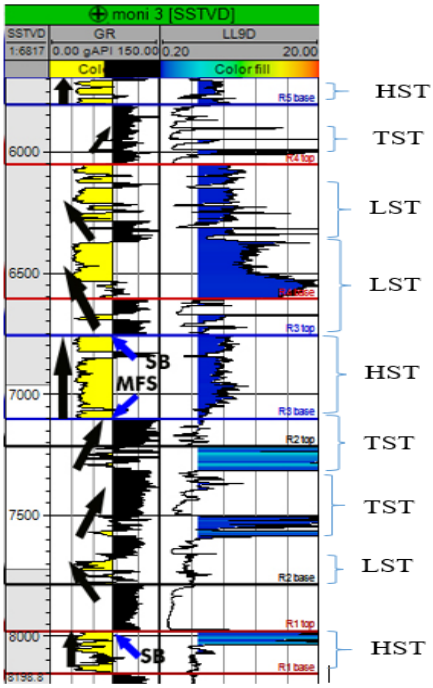

Fig. 18. Facies analysis from log using well Moni-3

(HST – Highstand system tract, TST – Transgressive system tract, LST – Lowstand system tract)

Seismic Facies Analysis

Six seismic facies were recognized using the characteristic of amplitude, frequency, and continuity and reflection configuration. Labelled A, B, C, D, E and F (Fig.19). The facies were defined primarily on the basis of seismic reflection patterns and the amplitude of their reflections.

The chaotic reflection beneath facie A is probably the basement. The base of Facie A is charcterized by a

ISSN No. 2321-2705 | DOI: 10.51244/IJRSI |Volume XI Issue III March 2024

hummocky and chaotic, highly discordant and discontinous medium to high reflection, beneath Facie B there is a generally very chaotic reflection pattern, beneath Facie C we have a subparallel discontinous wavy reflection, beneath Facie D we have a subparrallel dicontinous reflection while beneath Facie E and Facie F we have a continous parrallel and subparallel reflection (Fig. 20.

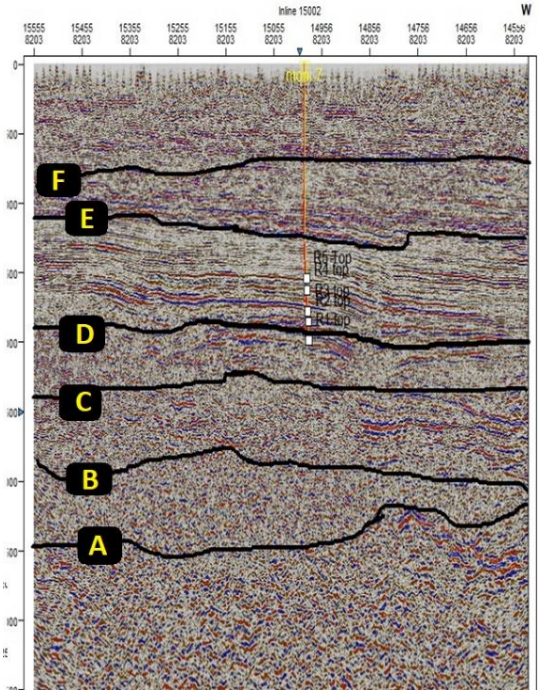

Fig. 19. Seismic inline 15002 section showing the marked facies

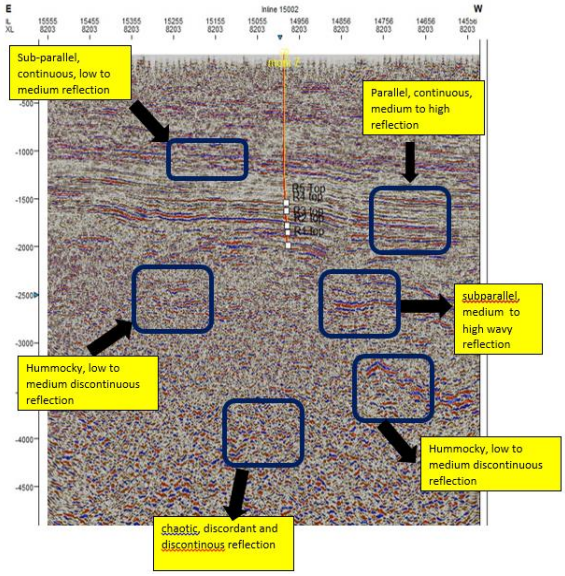

Fig. 20. Seismic Inline 15002 Section showing the seismic facies

CONCLUSION

Structure and Stratigraphic analysis from well logs and 3-D Post stack time migrated seismic data has been used to characterize “Moni” field. Three reservoirs (R1, R2 and R3) were identified from the well log analysis and lithostratigraphic correlation was carried out for the reservoirs. The well was then tied to seismic using the checkshot data to map the top of the reservoirs.

Petrophysical analysis shows that three reservoirs delineated have a porosity ranging from 19.37% to 23.62%, permeability ranging from 1408.71 to 1855.36 mD, a Net-to-Gross ranging from 0.46 to 0.88, volume of shale ranging from 11.72% to 24.92%, Water saturation ranging from 37.24% to 47.96% and hydrocarbon saturation ranging from 52.04 to 62.76. The petrophysical analysis showed that the reservoirs are of good quality.

Time structure and depth structure maps were reviewed for the mapped horizons. Seven faults were picked, named F1, F2, F3, F4, F5, F6 and F7. Four of the faults (F1, F2, F4 and F5) are regional faults while three faults (F3, F5 and F6) are local faults. The structural analysis indicate that the closure are fault dependent. Anticlinal closure and fault assisted closures which are known as a good hydrocarbon prospect were recognized in the depth structure contour maps.

Two sequence boundary, one maximum flooding surface, two transgressive system tract, three highstand system tract and three low stand system tract were identified. Six seismic facies were also identified (labelled A, B, C, D, E and F). Well log facie analysis also indicates that the depositional environment of the reservoirs ranges from subaerial channel deposit, barrier bar deposit, and tidal channel deposit to delta distributary channel fill. Tidal channel sands usually possess a fair to good reservoir quality due to their high degree of heterogeneity while delta distributary channel fill are good reservoirs because they are of a relatively higher porosity. Only reservoir R1 is a subaerial channel deposit.

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