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EFFECTS OF HETEROGENEITY ON THE PETROPHYSICAL PARAMETERS OF SANDSTONE RESERVOIRS AND VOLUMETRICS IN "DEVO" FIELD, NIGER DELTA

David Oladimeji, O.,[1] Fadiya, S. L.[2]

[1] *Obafemi Awolowo University Ile-Ife, Nigeria*
[2] *Obafemi Awolowo University Ile-Ife, Nigeria*

Abstract

This study identified and correlated hydrocarbon bearing reservoirs, interpreted geological structures and petrophysical parameters and described facies and environment of deposition using seismic and well log data. These were with a view to assessing the impact of reservoir heterogeneity on petrophysical parameters and to determine the hydrocarbon potential of "Devo" Field, Niger Delta. Porosity, permeability, water saturation, net-to-gross, and hydrocarbon saturation with values ranging between 25.0 and 26.2%, 735.0 and 9019.4 mD, 15.3 and 67.5%, 49.6 and 57.3%, and 32.1 and 84.7% respectively. The Thomas-Steiber shaly-sand model analysis revealed that laminated shale was widely distributed all through the "Devo" Field reservoirs. Despite the dominance of laminated shale, the reservoir quality from porosities (26.0, 26.2, and 25.4%), permeability (5264.0, 4419.8, and 3658.8 mD) values revealed very good to excellent qualities according to classifications made by Levorsen. Structural framework interpretation showed that sealing fault closure which includes the growth faults F12, F13, and F17 with antithetic faults F18 and F22 constitute the structural heterogeneity influencing oil trapping. Utilizing Amaefule's technique, the crossplots of Reservoir Quality Index and Normalized Porosity indicated increasing reservoir quality in relation to the normalized porosity. Facies description demonstrated that five different facies (channel, tidal channel, mouth bar, shoreface, and tidal flat) were associated with the reservoirs and their environments of deposition were categorized as fluvial and shallow marine environments. The volumetric estimations showed that Reservoir 1 closures have Prospects 1 (241.6 Million of Stock Tank Barrels, MMSTB) and 2 (78.1 MMSTB) in terms of calculated Stock Tank Original Oil-In-Place (STOOIP). Reservoir 2 closures have Prospects 1 (250.6 MMSTB) and 2 of (127.7 MMSTB), while Reservoir 3 closures have Prospects 1 (48.8 MMSTB) and 2 (63.2 MMSTB) in terms of the calculated STOOIP.

Keywords: Heterogeneity; Petrophysical Parameters; Sandstone Reservoir; Reservoir Quality; Seismic Attributes.

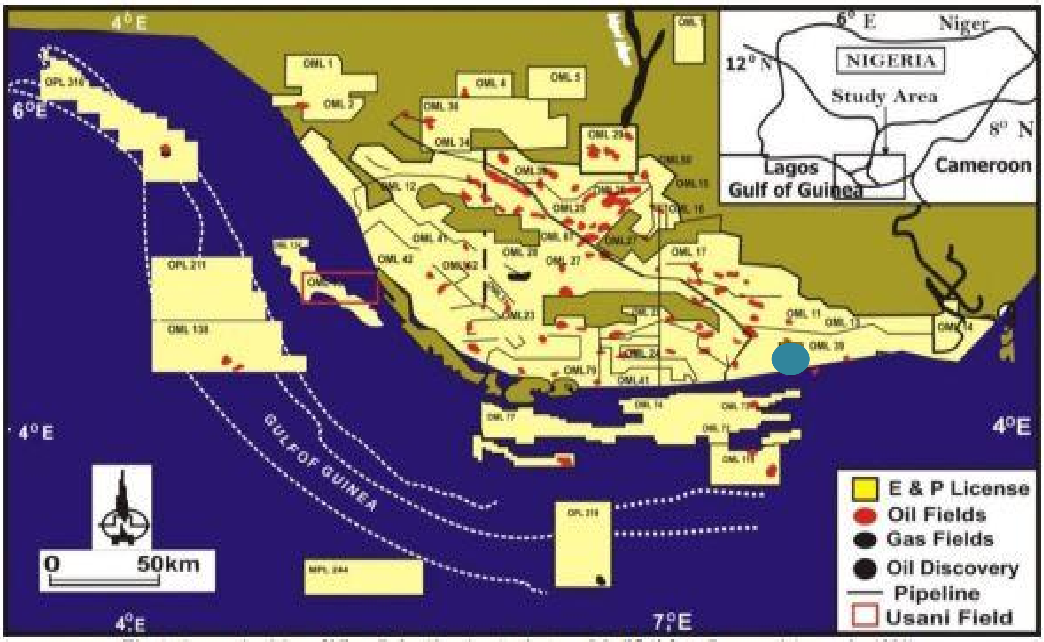
* Fadiya, S. L., Tel.: 08033320230; *E-mail:* fadiyalawrence@yahoo.co.uk

1.0. INTRODUCTION

The term “Heterogeneity” is defined as the variable complexities of reservoir properties and its relationship to fluid flow (Alpay, 1972). Modern day researches on deltaic reservoirs especially the Niger Delta confirmed the presence of heterogeneity in the Niger Delta and were largely attributed to complex depositional system with processes such as sedimentation, erosion, diagenesis, faulting and fracturing, shale distribution, and facies differences which constitute the heterogeneity nature of such reservoirs (Weber, 1986; Schenk, 1988). 3-D Seismic and Well Logs datasets are the two important geological tools which are used to interprete the stratigraphy and also in forecasting geomodels of both the subsurface and reservoir properties since these affects production performance and prediction (Nanaghan, 2016; Slatt and Galloway, 1993). Other important methods for evaluating heterogeneity involves the use of statistical measures which were the Dykstra Parson Permeability variation, Lorenz Coefficient Variation, and Coefficient of Variation. Cross-well datasets have also been considered an important parameters in evaluating heterogeneity by constraining stochastic simulation and realization which is a more likely direct approach to geostatistical modelling (Bonnell and Hurich, 2008). Tausif (2008) established the relationship between sandstone heterogeneity and reservoir quality using the equations that relates to the techniques of Amaefule (1993). Other authors also described the use of static and dynamic heterogeneity with statistical measures such as the Lorenz coefficient variation. The understanding of the type of shale which are low permeability baffles that affect fluid flow are also very important since they affects reservoir quality properties which are the porosity and the permeability values (Mode *et. al.,* 2013). Such shale or clay particles with different morphology and geometry may be dispersed, structural, and laminated shale (Schlumberger, 1972). They may occur singly or multiple in a sandstone reservoir. Depositional environments which ranges from arid sand dunes, fluviatile, and deltaic shallow and deep marine environments, can be adequately interpreted using well logs. This well log involved the use of gamma ray log signatures or motifs as described and defined by several authors which includes Cant (1992). Different types of heterogeneity includes the microscopic, megascopic, gigascopic, and fieldwide scale of heterogeneity. These types of heterogeneities were effectively discussed with core samples to understand properties such as the pores, grains size, sediments structure, geometry, stratification, and wide variation in litho-facies. These properties were later used in defining the scales of heterogeneity which were the wellbore, interwell, and fieldwide scale (Weber, 1986).

1.1. Study Area

The Niger Delta is located in the Southern parts of Nigeria, between Latitudes 3° 00' N and 6° 00' N and Longitude 5° 00' E and 8° 00' E (Nwachukwu and Chukwura, 1986). “DEVO” Field is located within the Coastal Swamp Depobelt, Onshore Niger Delta. “DEVO” Field covers an area of 207 km^2 and lies between Latitudes 4°24' N and 4°37' N and Longitudes 6°30' E and 10°30' E. The field belongs to Shell Petroleum Development Company. For this research, the field has been code-named “DEVO” for proprietary measures. The approximate location of “DEVO” Field is shown in Figure 1.1.



Devo Field

Fig. 1.1: Concession Map of the Niger Delta showing the Study Area Location (Doust and Omatsola, 1990)

1.2. Geology of the Niger Delta

The Niger Delta is one of the most important sedimentary basin in Nigeria as far as size and thickness of sediments. It is likewise the most essential from the financial perspective as its petroleum reserves give a substantial piece of the nation's remote exchange profit (Sahota, 2006). The Niger Delta Basin is an extensional failed rift system which formed amid the seperation of the South American plate and the African plate, and also the opening of the South Atlantic. The Niger Delta frames an arcuate shape at the intersection of the Benue-Trough and the South Atlantic Ocean (Burke, 1972; Maloney *et al*., 2010). It lies at the southern margin of Nigeria and covers an approximate area of around 300,000 km^2 (Kulke, 1995) with sediment volume of 500,000 km^3 (Hospers, 1965), sediment thickness running from 9,000 to 12,000 m and extends in excess of 300 km from apex to mouth (Doust and Omatsola, 1990). Since the onset of Eocene to Recent, the delta has prograded southwestward forming depobelts that were the most active portion of the delta (Doust and Omatsola, 1990). The stratigraphy of the Niger Delta had been widely debated and concluded as three main stratigraphical units. These formations were deposited due to series of transgression and large regressive forces which were action or cycles of the sea level changes leading to formation of the three formations with variable lithological properties (Short and Stauble, 1967). The sections of these formations are depicted by Short and Stauble (1967) and were discussed in different papers (Avbovbo, 1978; Doust and Omatsola, 1990; Kulke, 1995). The major three geologic formations built up Tertiary sequence of the Niger Delta comprises of the Akata, Agbada and Benin Formations in ascending orders which were deposited in marine, transitional and continental environments respectively. The three well known important formations of the Niger Delta are expatiated in Figure 1.2.

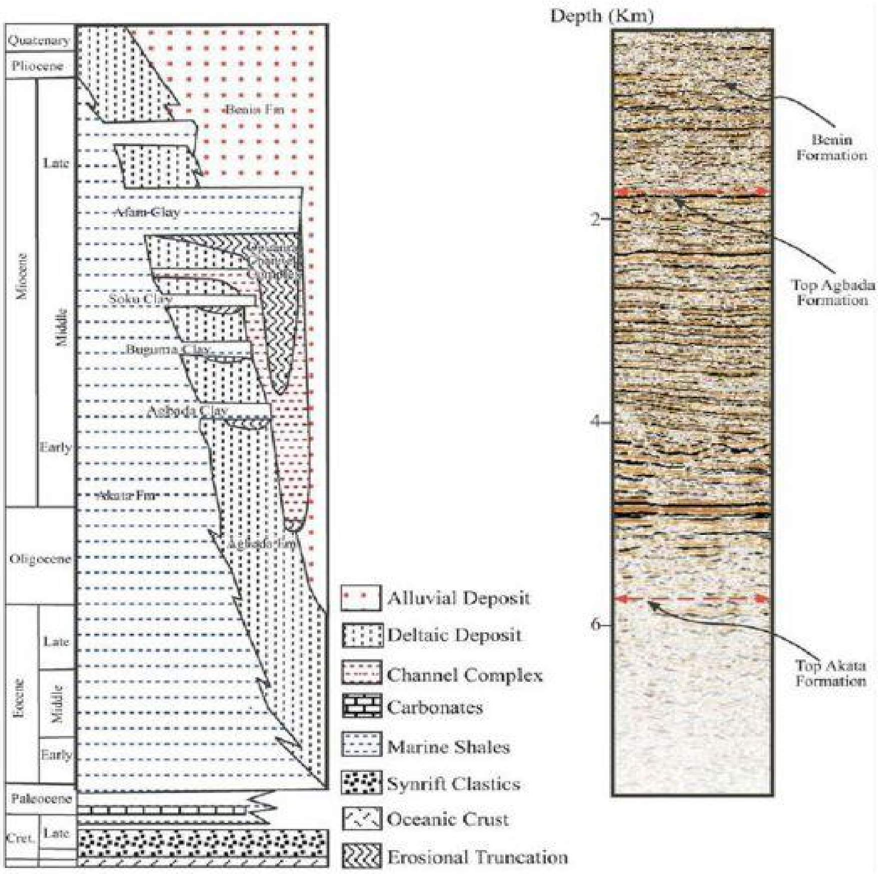


Fig. 1.2: Niger Delta Regional Stratigraphy and Variable Density Seismic Display of the Main Stratigraphic Units with Corresponding Reflections (Lawrence *et al.,* 2002)

2.0. MATERIALS AND METHODOLOGY

A dataset consisting of (207 km^2) 3-D migrated seismic data, comprising of eight hundred (800) inlines, nine hundred (900) crosslines, suite of open-hole well logs for six wells from the "Devo" Field were made available for this study by Shell Petroleum Development Company Limited, Nigeria. The six wells were code-named DEVO-1, DEVO-2, DEVO-3, DEVO-4, DEVO-5, and DEVO-13 for proprietary reasons. Checkshot data was made available for DEVO-1 well only.

Well header information revealed that the wells were drilled to a total depth of 12023 ft MD, 12254 ft MD, 7500 ft MD, 10600 ft MD, 12400 ft MD, and 12500 ft MD for DEVO-1, DEVO-2, DEVO-3, DEVO-4, DEVO-5, and DEVO-13 respectively. Table 2.1 displays the summary of the well logs and checkshot data available for the study while Figure 2.1 shows the basemap of the study area. The 3-D seismic volume were supplied in SEG-Y format, the well log data in LAS format and checkshot data in ASCII format. The dataset were interpreted with the aid of the Petrel Exploration and Production Software, Rokdoc, and Microsoft Excel softwares. These were utilized at various phases of the interpretation to accomplish the particular aim and target of the research. The methodology workflow to accomplish the set goals is as summarized in Figure 2.2.

Table 2.1: Summary of the Available Datasets for Each of the Wells

Well Log Types	**DEVO-1**	**DEVO-2**	**DEVO-3**	**DEVO-4**	**DEVO-5**	**DEVO-13**
Gamma Ray	√	√	√	√	√	√
Spontaneous Potential	√	√	√	√	√	√
Sonic	×	√	√	√	×	×
Caliper (CAL)	×	√	×	√	×	√
Neutron Porosity (NPHI)	×	√	×	×	×	×
Bulk Density (RHOB)	×	×	√	√	√	√
Deep Resistivity (Deep Res)	√	√	√	√	√	√
True Resistivity (Res)	√	√	√	√	√	√
Resistivity SLW	×	×	√	√	√	×
Micropherically Focused Resistivity Log	×	×	√	×	√	×
Check Shot Data	√	×	×	×	×	×

KEY: √ = AVAILABLE, × = NOT AVAILABLE

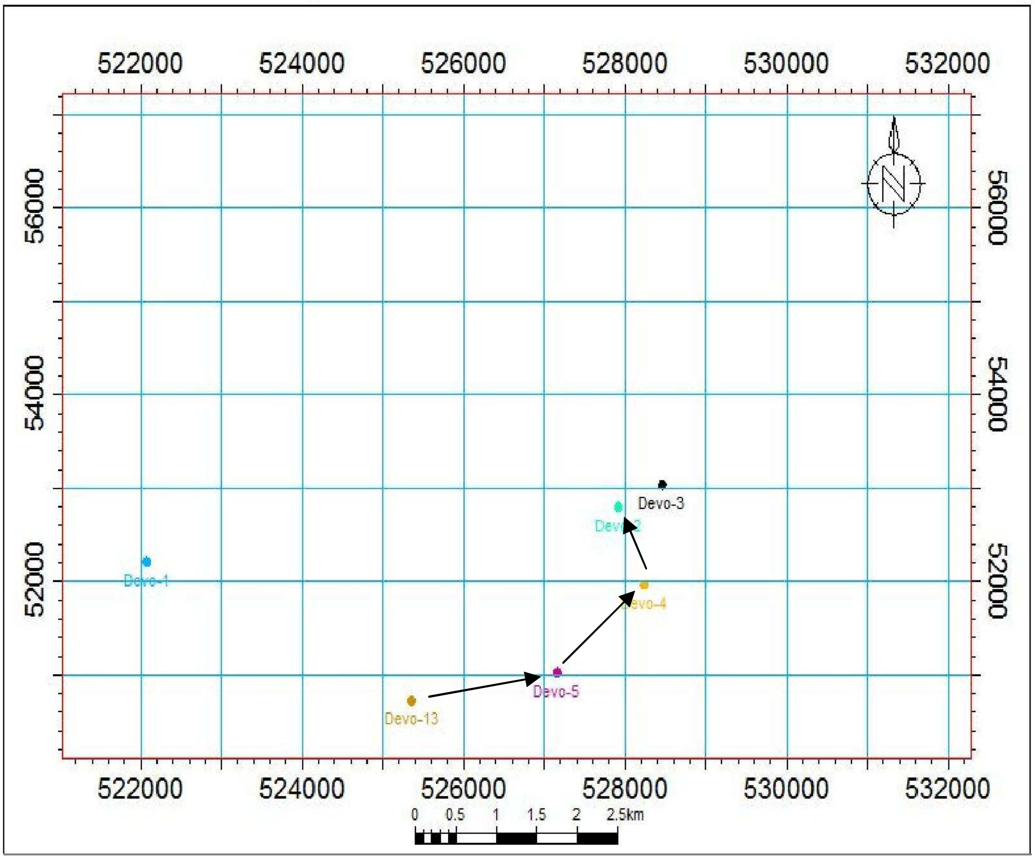


Fig. 2.1: Base Map of the Study Area

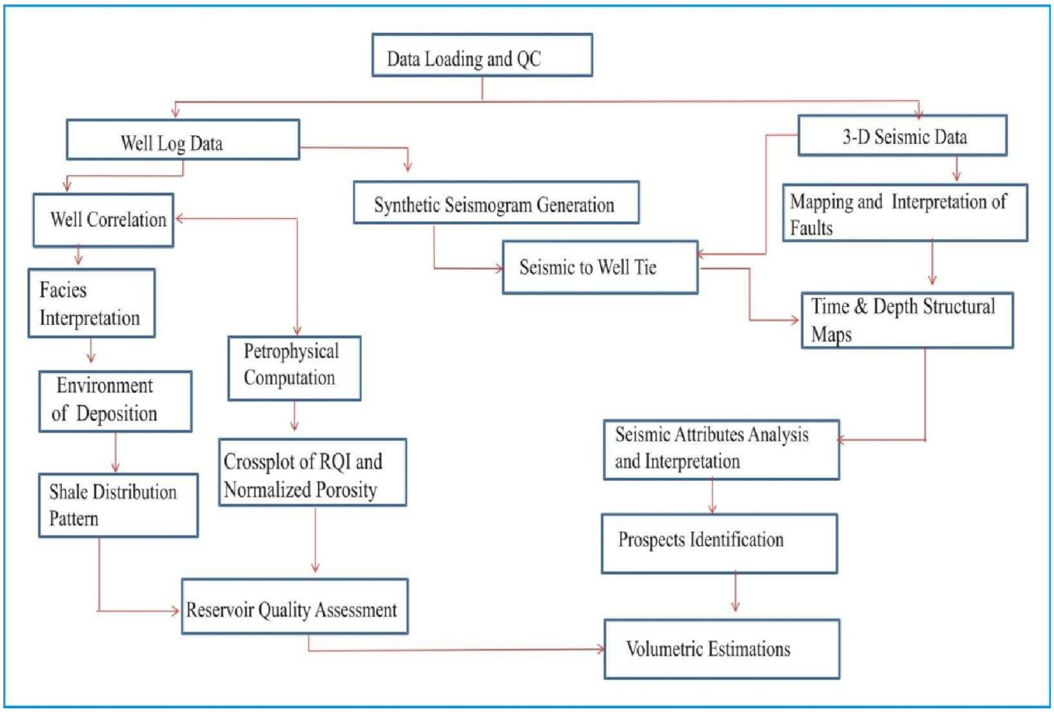


Fig. 2.2: Methodology Workflow

3.0. RESULTS AND DISCUSSION

3.1. Correlation of Identified Reservoir Sands

Well log correlation of the delineated reservoir sand units across the four (4) wells in the study area showed that each of the delineated three (3) reservoir sands units extended laterally across the four wells (Fig. 3.1). The correlated reservoir sand units varied in thickness and depth of occurrence in the individual wells.

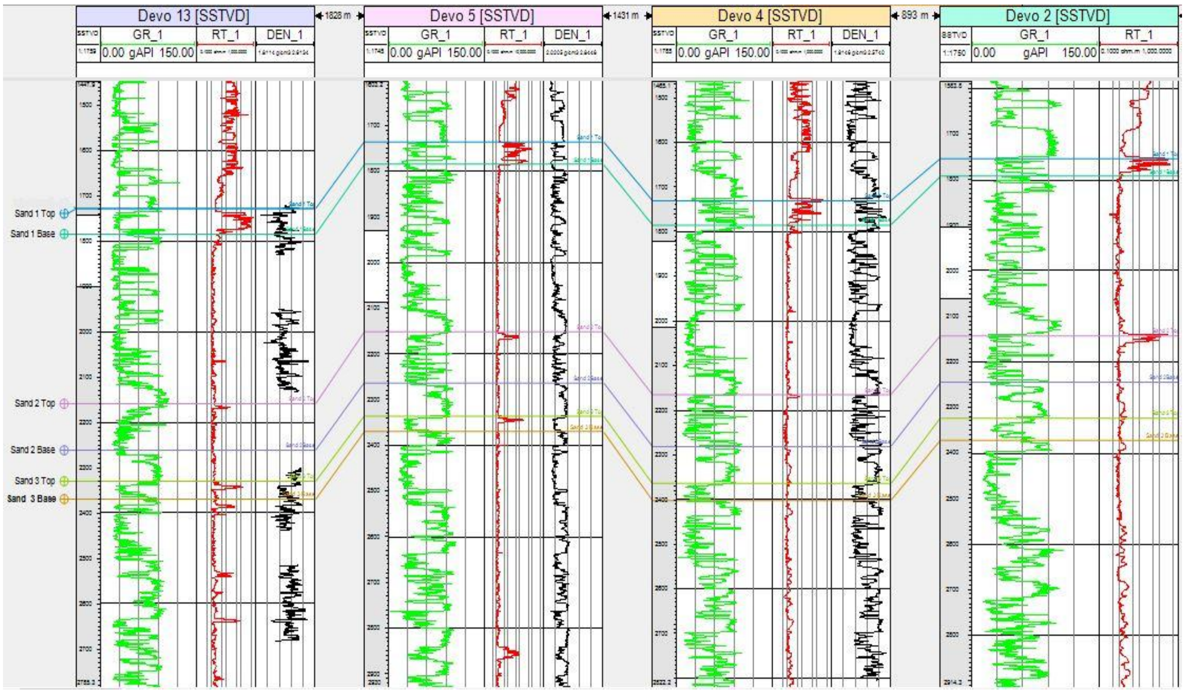


Fig. 3.1: Well Correlation of "DEVO" Wells 13, 5, 4, and 2

3.2. Reservoir Identification

Well log analysis resulted in the identification of three (3) prospective hydrocarbon–bearing sands (Sand 1, Sand 2, and Sand 3) penetrated by wells drilled in the study area. On the basis of relatively low gamma ray values and corresponding high resistivity readings, all the identified reservoir sands were found to be hydrocarbon-bearing.

3.3. Seismic Interpretation

3.3.1. Volume Attribute (Variance Edge)

The Variance Edge was applied to the realized seismic volume. The Variance Edge estimates local variance in the signal and it is useful for isolating discontinuities such as faults in the horizontal continuity of amplitude. Faults which were not clearly visible on the conventional horizontal time slice became more visible on the variance edge horizontal time slice. This helped in the identification of thirty-nine (39) faults in the study area. The faults were labeled F1 through to F39 (Fig. 3.2).

3.3.2. Fault Interpretation

Faults were mapped across 3-D seismic sections. The faults (F1-F39) were interpreted across the field as seen on the seismic section. All the faults were interpreted as normal faults with faults (F1, F2, F3, F4, F12, F13, F16, F17, F18, F19, F20, F22, F24, and F31) are categorized as major faults in the field.

Variance Edge Attribute and Timeslices were used to guide in fault interpretation (Fig. 3.2). The growth faults include F12, F13, and F17 while the antithetic faults include F18 and F22. The major trend is the East-West (E-W) direction with a good number of them dipping Southwards (F1, F2, F3, F4, F8, F21, F23, F24, F31, F36, and F38) and few of the faults (F14, F15, F16, F22, F26, F32, and F39) dipped North-West. Rollover anticlinal structures were seen across the growth faults on the seismic section.

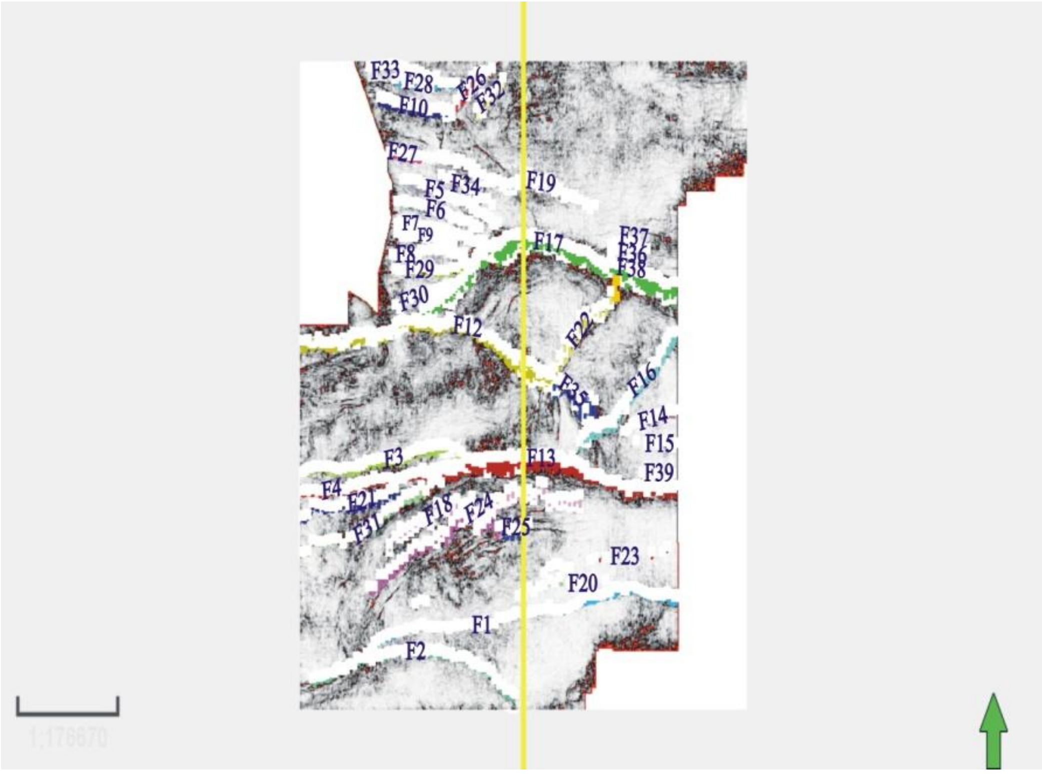


Fig. 3.2: Variance Edge Attributes showing F1-F39 Faults at Timeslice 1752 ms

3.3.3. Well-to-Seismic Tie

Well to seismic tie had been achieved through the generation of synthetic seismogram for the "Devo" Field using sonic and density logs together with the checkshot data from DEVO-1 well. The synthetic seismogram generated showed a fair to good tie after well adjustment was done. The results showed that the identified reservoir sand tops tied to seismic peaks and trough (Fig. 3.3).

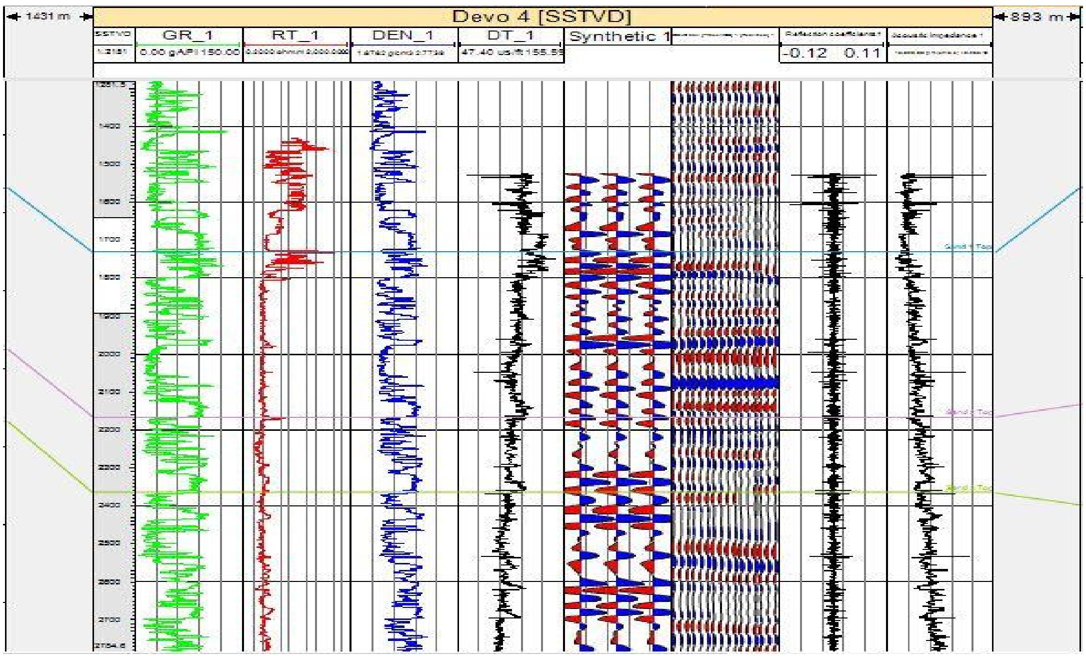


Fig. 3.3: Well-to-Seismic Tie on DEVO-4 Well

3.3.4. Horizon Mapping on Seismic Section

After proper Well-to-Seismic Tie, three horizons (H1, H2, H3) corresponding to hydrocarbon bearing reservoir sand tops were mapped on seismic sections (Fig. 3.4). The continuity and the strength of the reflections that mark the top of these reservoirs were observed during mapping.

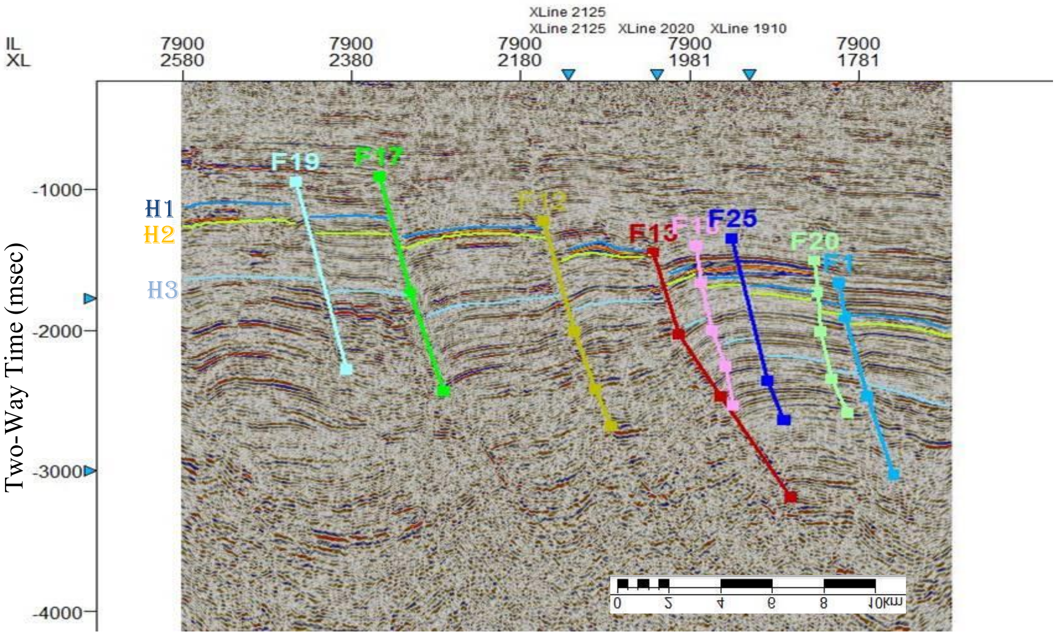


Fig. 3.4: Horizons H1, H2, and H3 showing on Seismic Inline 7900

3.3.5. Generation of Time Structure Maps

The horizons mapped on both crosslines and inlines were utilized to create a 3-D Seed grid which was used in turn to produce time structure maps.

3.3.6. Time to Depth Conversion

Time to depth conversion was done with the aid of a velocity model and a second order polynomial function was generated using the Schlumberger Petrel Software to generate the depth structural maps.

3.4. Computed Petrophysical Parameters of DEVO Field Reservoirs

The petrophysical parameters were calculated using standard empirical formulas. The results of the evaluated petrophysical parameters (Gross Sand Thickness, Net Sand, Net-to- Gross Ratio, Hydrocarbon Saturation, Water Saturation of the Flushed Zone, Water Saturation, Irreducible Water Saturation, Bulk Volume of Oil, Movable Hydrocarbon Index, Bulk Volume of Water, Volume of Shale, Formation Factor, Porosity, Permeability, Effective Porosity) are as presented in Table 3.1 – 3.5.

Table 3.1: Computed Petrophysical Parameters of DEVO-2 Well

Reservoirs	Top (ft)	Base (ft)	Gross Sand (ft)	Net Sand (ft)	Net to Gross (%)	S_h (%)	S_{xo}	S_w (%)	F	BVO	BVW	S_{wirr} (%)	MHI	Ø (%)	K (mD)	V_{sh} (%)	$Ø_{eff}$
Reservoir 1	5754	5880	126	63	50	85.5	1.7	14.5	10.7	36.1	3.4	7.3	8.5	26.6	4746.5	12.9	23.2
Reservoir 2	7027	7363	336	201	60	55.5	2.1	44.5	10.1	41.4	11.1	7.1	21.2	27.3	5625.2	8.6	25.0
Reservoir 3	7620	7783	163	52	32	6.3	2.5	93.7	13.7	27.7	16.6	8.3	37.5	23.7	2209.4	25.5	17.7

Table 3.2: Computed Petrophysical Parameters of DEVO-4 Well

Reservoirs	Top (ft)	Base (ft)	Gross Sand (ft)	Net Sand (ft)	Net to Gross (%)	S_h (%)	S_{xo}	S_w (%)	F	BVO	BVW	S_{wirr} (%)	MHI	Ø (%)	K (mD)	V_{sh} (%)	$Ø_{eff}$
Reservoir 1	5680	5854	174	61	35.1	74.1	1.92	25.9	19.7	26.9	4.2	9.9	13.5	20.0	735.9	19.0	16.2
Reservoir 2	7103	7484	381	206	54.1	8.1	2.47	91.9	13.1	33.5	19.9	8.1	37.2	24.2	2543.1	10.9	21.6
Reservoir 3	7756	7880	124	48	38.7	1.1	2.51	98.9	11.7	34.1	22.2	7.6	39.4	25.5	3636.5	12.3	22.4

Table 3.3: Computed Petrophysical Parameters of DEVO-5 Well

Reservoirs	Top (ft)	Base (ft)	Gross Sand (ft)	Net Sand (ft)	Net to Gross (%)	S_h (%)	S_{xo}	S_w (%)	F	BVO	BVW	S_{wirr} (%)	MHI	Ø (%)	K (mD)	V_{sh} (%)	$Ø_{eff}$
Reservoir 1	5696	5858	162	73	45.1	89.1	1.6	10.9	9.6	38.0	2.8	6.9	6.8	27.9	6553.9	8.7	25.5
Reservoir 2	7060	7429	369	150	40.7	36.4	2.3	63.6	10.9	38.6	14.8	7.4	27.7	26.4	4468.2	12.3	23.2
Reservoir 3	7667	7775	108	80	74.1	67.3	2.0	32.7	10.1	42.5	8.3	7.1	16.4	27.3	5625.2	6.8	25.4

Table 3.4: Computed Petrophysical Parameters of DEVO-13 Well

Reservoirs	Top (ft)	Base (ft)	Gross Sand (ft)	Net Sand (ft)	Net to Gross (%)	S_h (%)	S_{xo}	S_w (%)	F	BVO	BVW	S_{wirr} (%)	MHI	Ø (%)	K (mD)	V_{sh} (%)	$Ø_{eff}$
Reservoir 1	5671	5869	198	139	70.2	90.1	1.6	9.9	8.60	39.5	26.0	6.6	6.2	29.4	9019.4	10.4	26.3
Reservoir 2	7082	7419	337	250	74.2	44.2	2.2	55.8	10.5	29.3	13.3	7.2	25.4	26.8	5042.7	10.6	23.9
Reservoir 3	7641	7770	129	69	53.5	55.3	2.1	44.7	12.20	35.2	9.5	7.8	21.3	25.0	3164.4	14.9	21.3

Table 3.5: Summary or Averages of the Computed Petrophysical Parameters of "DEVO" Field Reservoir

Reservoirs	Top (ft)	Base (ft)	Gross Sand (ft)	Net Sand (ft)	Net to Gross (%)	S_h (%)	S_{xo}	S_w (%)	F	BVO	BVW	S_{wirr} (%)	MHI	Ø (%)	K (mD)	V_{sh} (%)	$Ø_{eff}$
Reservoir 1	5700.3	5865.3	165	84	50.1	84.7	1.7	15.3	12.2	35.1	9.1	7.7	8.8	26.0	5264	12.8	22.8
Reservoir 2	7068	7424	356	202	57.3	36.1	2.3	64.0	11.2	35.7	14.8	7.45	27.9	26.2	4419.8	10.6	21.5
Reservoir 3	7671	7802	131	62.3	49.6	32.1	2.3	67.5	11.9	34.8	14.2	7.7	28.7	25.4	3658.8	14.9	21.7

3.5. Reservoir Heterogeneity and Reservoir Quality Assessment

3.5.1. Faulting and Fracturing of the Reservoir Intervals as it Influences Oil Trapping

A total of 39 faults (F1-F39) were interpreted across the field as seen on the seismic section. Most of the major faults were continuous throughout the seismic volume while some of the minor faults were not. All the faults were interpreted as normal faults with faults (F1, F2, F3, F4, F12, F13, F16, F17, F18, F19, F20, F22, F24, and F31) categorized as the major faults in the field. Variance Edge Attribute and Timeslices were used to guide fault interpretation. Faults (F12, F13, and F17) were interpreted as growth faults while the antithetic faults include F18 and F22. The faults trend generally is the East-West (E-W) direction with a good number of them dipping Southwards (F1, F2, F3, F4, F8, F21, F23, F24, F31, F36, and F38), and a few of the faults (F14, F15, F16, F22, F26, F32, and F39) dipped North-West. Rollover anticlinal structure is seen across the growth faults on the seismic section.

Seismic attributes were applied on Horizons 1, 2, and 3 Time Structure Maps which corresponds to Reservoirs 1, 2, and 3 respectively to generate attribute seismic maps. The Root Mean Square (RMS) Amplitude Surface Attribute applied to the map showed a confirmed Bright Spot which are high anomalous amplitude on the centre and the southern part of the map and also region of high reflectivity majorly at the eastern part of the map where the interaction of the sets of growth and antithetic faults have resulted in accumulation of hydrocarbons within the fault traps (Fig. 3.5).

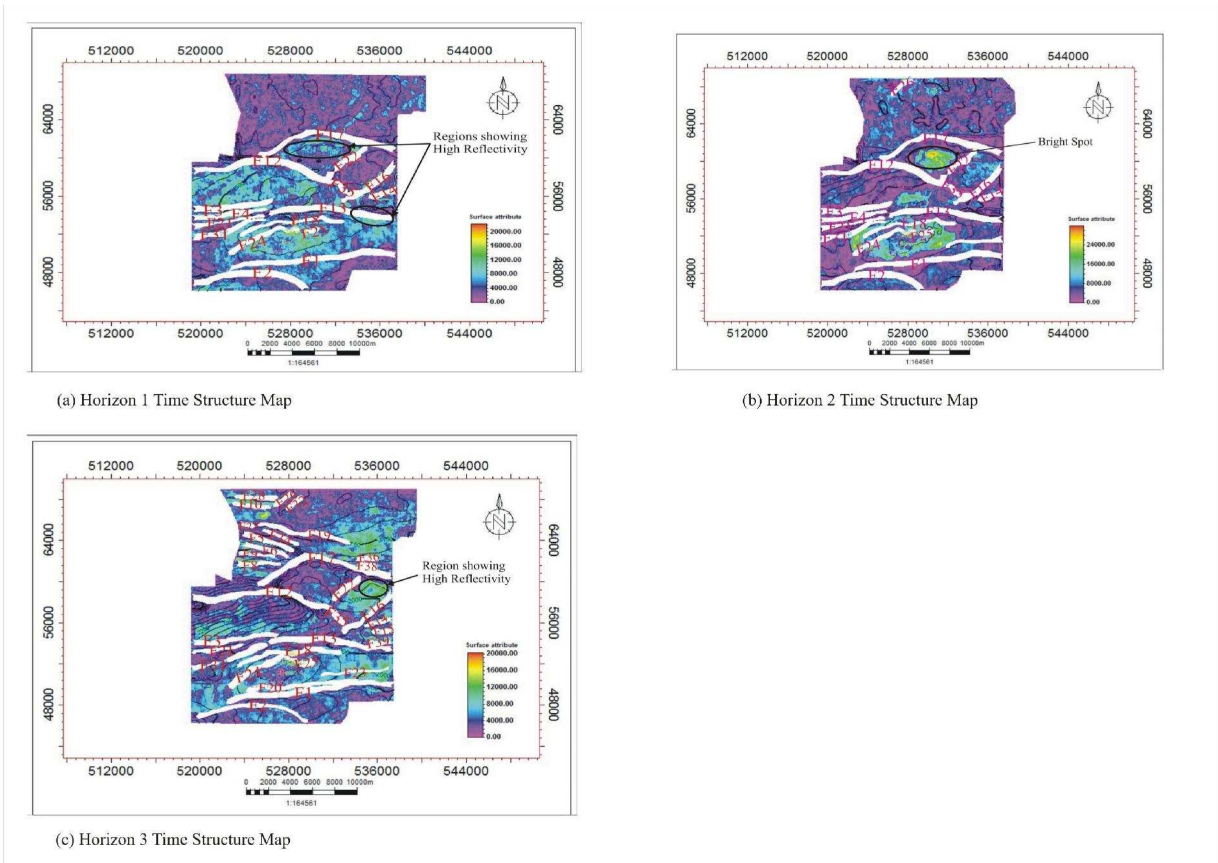


Fig. 3.5: Conformity of Faults Structures and Potential Hydrocarbon Accumulation using RMS Amplitude on Horizons 1, 2, and 3 Time Structure Maps Respectively

3.5.2. Shale/Clay Distribution

The Thomas-Stieber (1975), Shaly-Sand Model applied to show distribution pattern of shale/clay in "Devo" Field reservoirs revealed that the laminated shale is most drawn out and widely distributed in Devo-4, Devo-5, and Devo-13 wells (Fig. 3.6). Laminated shale has been known to have less implication on reservoir quality when compared to dispersed and structural clay/shale which usually have adverse effect on reservoir quality.

Petrophysical parameters such as porosity and permeability which are main reservoir quality parameters were calculated for "Devo" wells. For Devo-4 well, the values ranges from 20.0 - 25.5% and 735.9 - 3636.5 mD for both porosity and permeability respectively. Also for Devo-5 well, the values are 26.4 - 27.9% and 4468.2 - 6553.9 mD for both porosity and permeability respectively. For Devo-13 well, the porosity and permeability values range from 25.0 - 29.4% and 3164.4 - 9019.4 mD.

Although laminated shale does not affect effective porosity, water saturation, or horizontal permeability, but it may affect vertical permeability, leading to efficient horizontal fluid flow but impaired vertical fluid flow in “Devo” Field reservoirs.

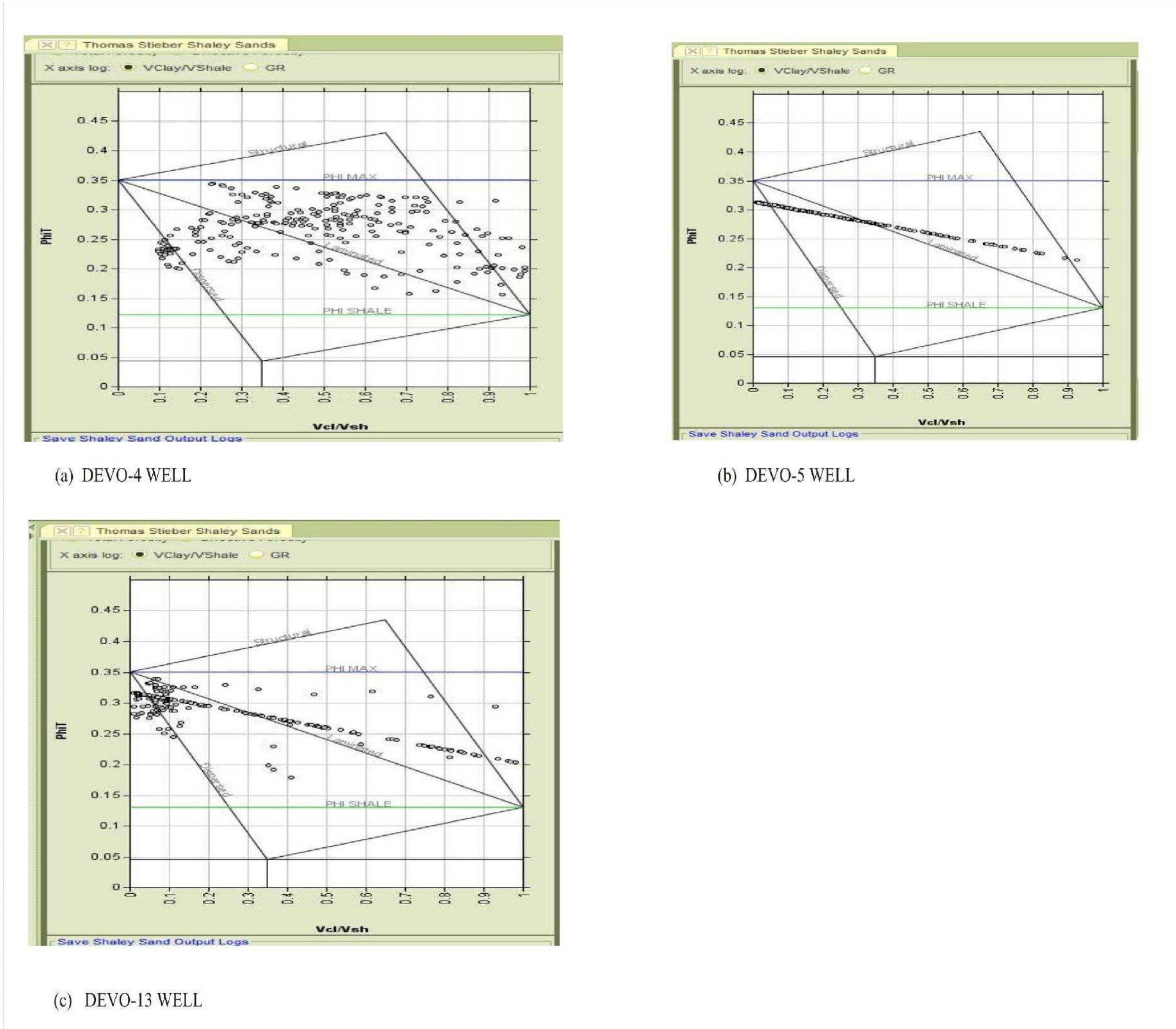


Fig. 3.6: Thomas-Stieber Shaly-Sand Model of Laminated Shale Distribution in the Reservoirs of “Devo” Wells

3.5.3. Relationship Between Heterogeneity and Reservoir Quality in “Devo” Field

The chart of the log-log plot of Reservoir Quality Index (RQI) against a Normalized Porosity (PHIz) should yield a straight line with a unit slope. The intercept of the unit slope line with Normalized porosity (PHIz) = 1, is described as the Flow Zone Indicator (Fitch *et al.,* 2010). The flow zone indicator is however an important parameter for describing Hydraulic Flow Unit.

LOG-LOG CROSSPLOTS FOR DEVO FIELD RESERVOIRS

The Reservoir Quality Index (RQI) of “Devo” Field reservoirs are directly related to the porosity (Normalized Porosity). Porosity and reservoir quality index relationship for Reservoirs (Sand 1, 2, and 3) for “Devo” Field has a good correlation coefficient. The crossplot showed a linear cluster of plot/points relationship between the two parameters which indicated that the reservoir quality index which increases upward across the y-axis showing a positive or good reservoir quality in relation to the normalized porosity in reservoirs (Fig. 3.7).

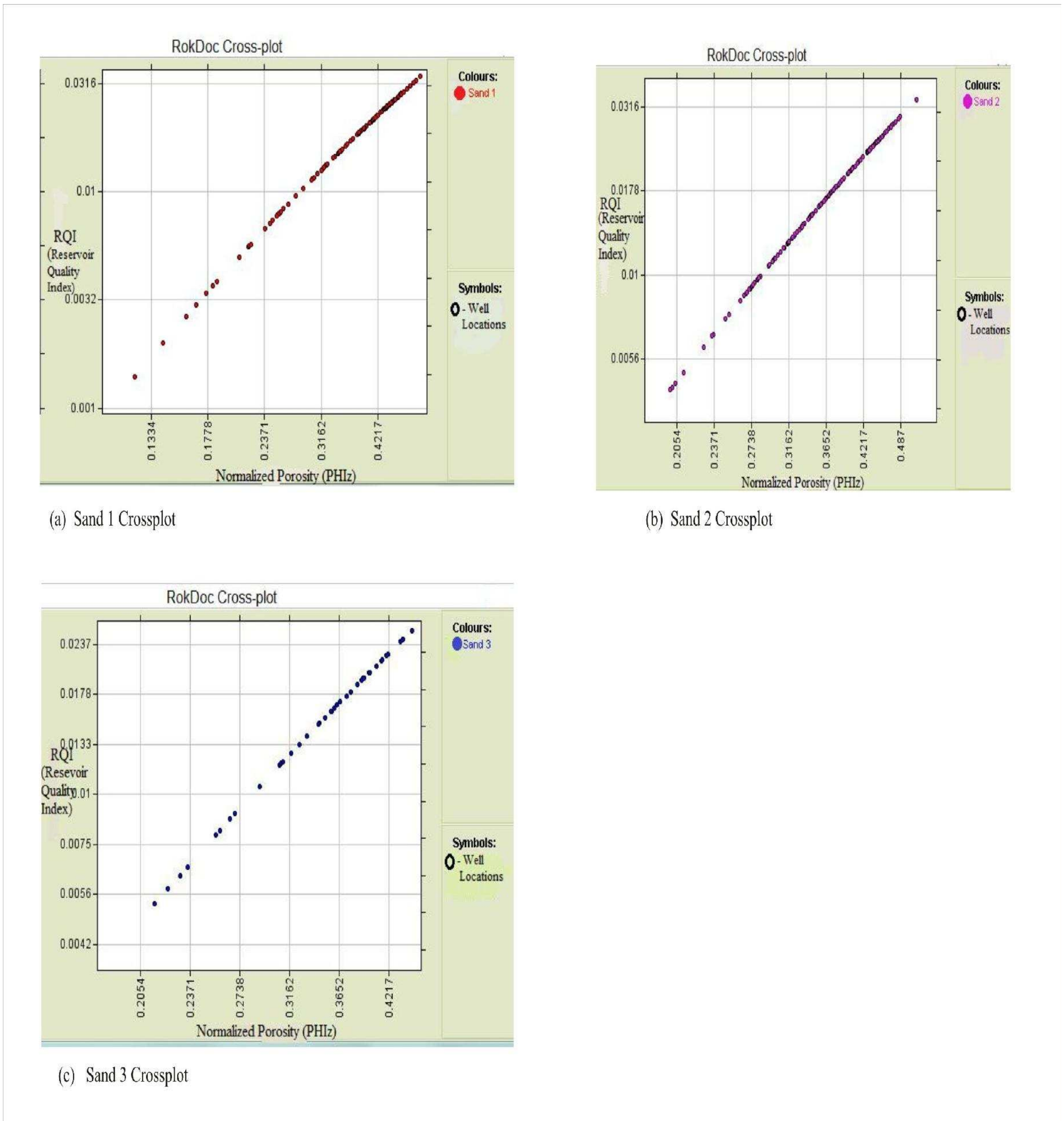


Fig. 3.7: Crossplots of Reservoir Quality Index (RQI) and Normalized Porosity (Sand 1, 2, and 3)

3.5.4. Vertical and Lateral Distribution of Facies, and Interbedding Characteristics of the Sandstone, Mudstone, and Other Rock Types

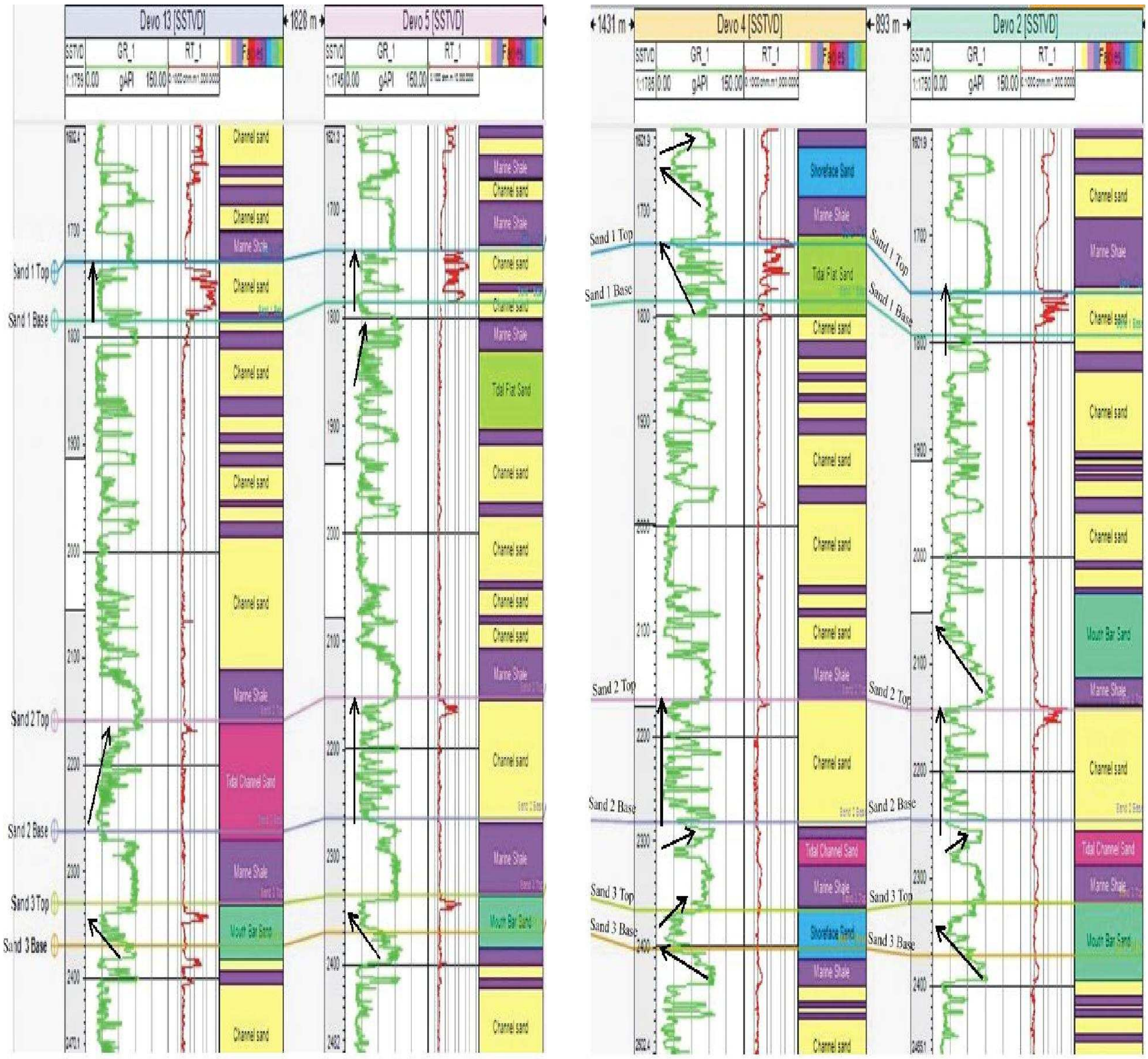
In "Devo" Field, six facies were delineated using the gamma ray log curves as described by Cant (1992). They included the Channel Sand, Tidal Channel Sand, Tidal Flat Sand, Mouth Bar Sand, Shoreface Sand and Marine Shale facies (Fig. 3.8). These facies constitute the heterogeneity of the study area due to the fact that they occur during different sea energy level and stacking patterns leading to different lithology and environment of deposition (Kulke, 1995).

3.5.5. Environment of Deposition of the Study Area

The shallow-marine and coastal environment according to Siddiqui *et al.* (2017) is defined as the depositional system that exist between the landward influence of the marine processes and the seaward influence of continental, mainly fluvial (river) processes. Shallow-marine environments are for the most part considered and grouped according to physical process regime.

The main physical processes operating in shallow-marine setting are waves and storms, tidal currents and river-derived flows (Siddiqui *et al*., 2017).

Fluvial deposits, also called alluvial deposits, are sediments that are usually formed by action of river, stream, and due to associated gravity flow processes. The environmental settings of fluvial deposits, are categorized into alluvial fan and river deposits. Facies association in Fluvial depositional environment include channel fill, floodplain, levee, and crevasse splay. Deltas and deltaic deposits are usually formed from the processes and interaction of fluvial and coastal processes.



Stacking Patterns

= Aggradational (Lowstand System Tract)

= Retrogradational (Transgressive System Tract)

= Progradational (Highstand System Tract)

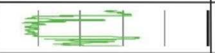
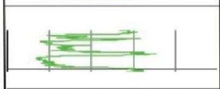
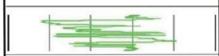
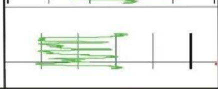
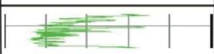
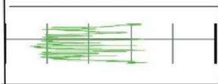
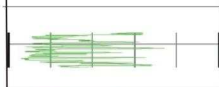
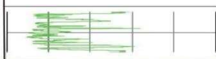
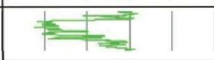
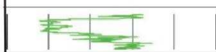
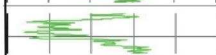
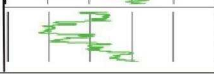
= Progradational and Retrogradational (Regressive and Transgressive)

Fig. 3.8: Gamma Ray Log Signatures for Facies Definition of the Study Area

Therefore fluvial action and processes are very vital in a deltaic environment (Allen, 1965).

The environment of deposition of "Devo" Field reservoirs were delineated from the combined play of the stacking patterns and the results of the facies analysis from the field which are in line with previous studies done on coastal swamp depobelts by Doust and Omatsola (1990) and Ajaegwu *et al.* (2012). From the results from the facies, stacking patterns, and gamma ray log curves analysis of "Devo" Field, the environment of deposition of "Devo" Field are categorized as fluvial to shallow marine environments subdivided into shoreface, tidal channel, distributary channel, fluvial channel, and tidal flat environments and were fully discussed in Table 3.6.

Table 3.6: Inferred Environment of Deposition in "Devo" Field

Depth (ft)	Sands	GR log shapes/ Stacking Patterns	Characteristic Description	Inferred Depositional Environment
5671 - 5880	Sand 1		Gamma ray log motif is Blocky Shaped.	Channel
			*The gamma ray signature is cylindrical shaped with blocky thickly bedded sand with few interbedded shale.*	Fluvial Channel
			Gamma ray log motif is Funnel Shaped and Serrated.	Tidal Flat
			*The gamma ray signature is cylindrical shaped with blocky thickly bedded sand with few interbedded shale.*	Fluvial Channel
7027 -7484	Sand 2		Gamma ray log motif is Bell Shaped or Fining Upward Trend.	Tidal Channel
			*The gamma ray signature is cylindrical shaped with blocky thickly bedded sand with few interbedded shale.*	Fluvial Channel
			*The gamma ray signature is cylindrical shaped with blocky thickly bedded sand with few interbedded shale.*	Fluvial Channel
			Gamma ray log motif is Blocky Shaped.	Channel
7620 - 7880	Sand 3		Gamma ray log motif is Funnel Shaped with sharp top.	Mouth Bar
			Gamma ray log motif is Funnel Shaped with sharp top.	Mouth Bar
			Gamma ray log motif is Funnel Shaped and Symmetrical.	Shoreface
			Gamma ray log motif is Funnel Shaped with sharp top.	Mouth Bar

3.6. Seismic Attributes Analysis of the Study Area

The Amplitude Seismic Attributes were applied in "Devo" Field to show areas of high amplitude, Direct Hydrocarbon Indicators, and areas with high Reflectivity which are potential reservoir rock with hydrocarbon accumulation. The amplitude levels are portrayed by reddish-yellow colouration for high amplitude and light to dark blue colour for low amplitude zones.

(i) Lower Loop Area Attribute Map

Lower Loop Area attribute was applied to the Horizons 1, 2, and 3, Maps corresponding to the three reservoirs. There were regions which showed high amplitude as the yellowish-red areas around the anticlinal structure at the central part and southern parts of the map in Horizon 1 Map (Fig. 3.9a). There were also high amplitude areas in the central and eastern parts of the map on Horizon 2 Map (Fig. 3.9b). While Bright Spots were identified at the eastern and central parts of the map on Horizon 3 Map (Fig. 3.9c). Bright Spot which is known as a Direct Hydrocarbon Indicator (DHI) and high amplitude are suggestive of the presence of reservoir rock having hydrocarbon accumulation.

(ii) Mean Amplitude Attribute Map

Mean Amplitude Attribute was applied to the Horizon 1, 2, and 3, Maps corresponding to the three reservoirs. There were regions which showed high amplitude areas as yellowish patches around the anticlinal structure in the central and eastern parts of the map on Horizon 1 Map (Fig. 3.10a). There were also blueish patches at the central part of the map identified as low amplitude area on Horizon 2 Map identified as Dim Spot (Fig. 3.10b). High amplitude areas were also identified on the western and central parts of the Horizon 3 Map (Fig. 3.10c). These high and low amplitude areas are suggestive of the presence of a reservoir rock with potential hydrocarbon accumulation.

(iii) Root Mean Square Amplitude Attribute Map (RMS)

RMS Amplitude Attributes was applied to the Horizons 1, 2, and 3, Maps corresponding to the three reservoirs. There were regions with high Reflectivity on the anticlinal structure in the central and eastern parts of the map on Horizon 1 Map (Fig. 3.11a). There were also yellowish-red patches identified as Bright Spots at the central and southern parts of Horizon 2 Map (Fig. 3.11b). The area with High Reflectivity was lastly identified at the eastern part of the Horizon 3 Map (Fig. 3.11c). The high anomalous amplitude areas identified as Bright Spots and regions with high reflectivity are suggestive of the presence of reservoir rock with hydrocarbon accumulation.

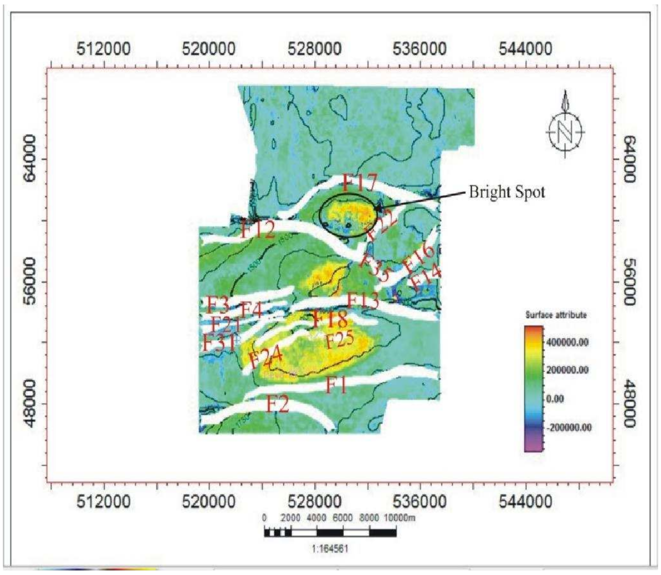


Fig. 3.9a: Lower Loop Area Surface Attribute Showing on Horizon 1

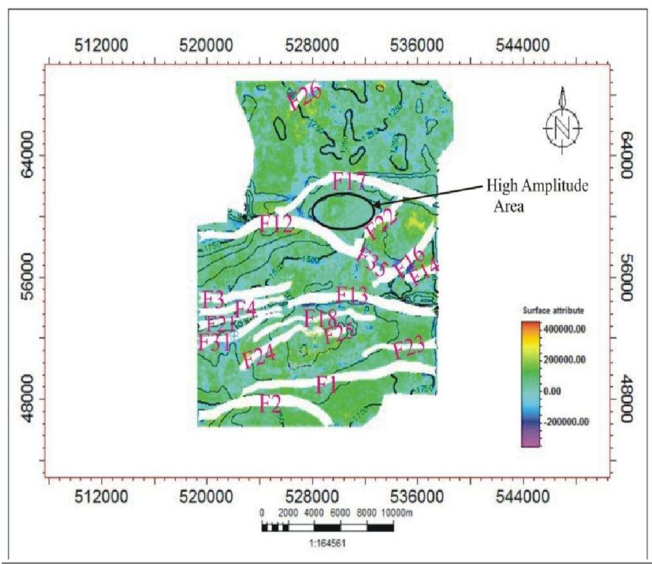


Fig. 3.9b: Lower Loop Area Surface Attribute Showing on Horizon 2

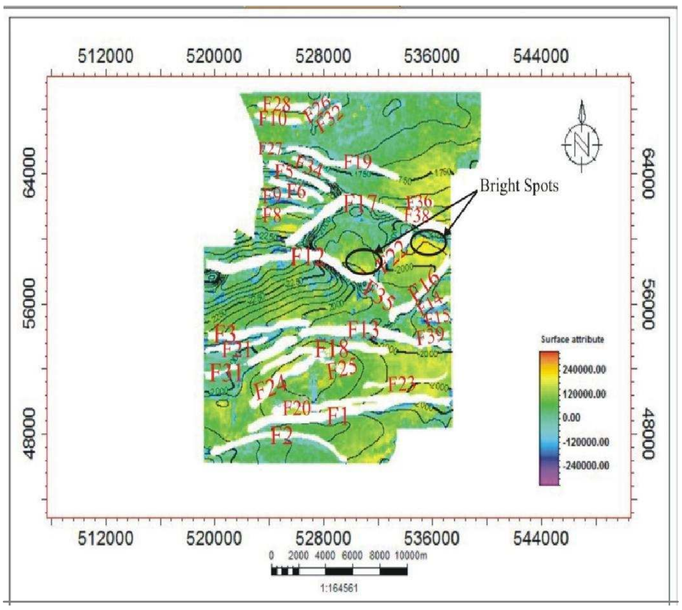


Fig. 3.9c: Lower Loop Area Surface Attribute Showing on Horizon 3

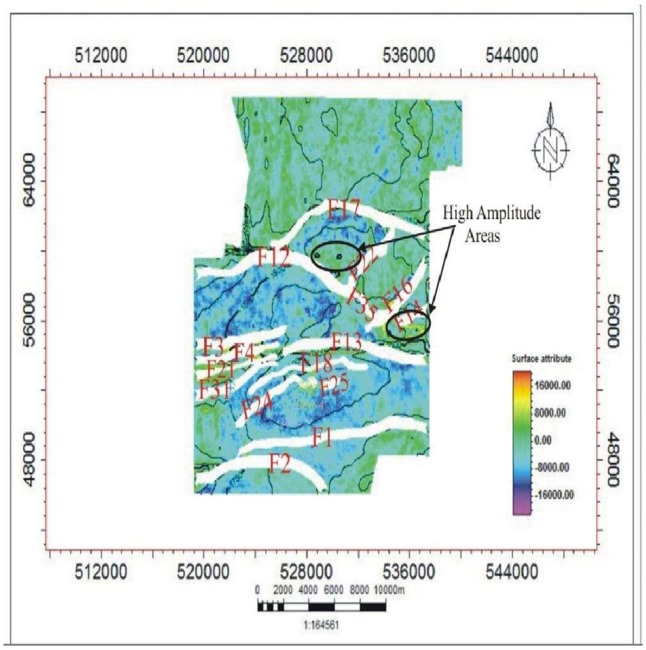


Fig. 3.10a: Mean Amplitude Surface Attribute Showing on Horizon 1

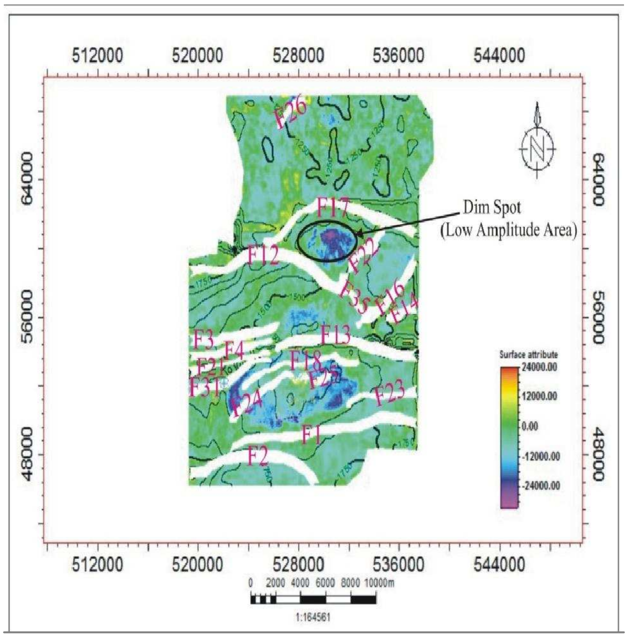


Fig. 3.10b: Mean Amplitude Surface Attribute Showing on Horizon 2

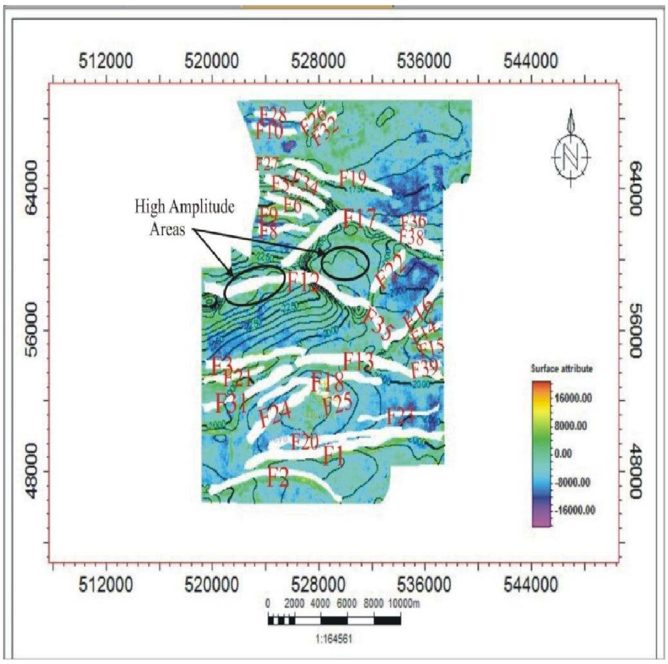


Fig. 3.10c: Mean Amplitude Surface Attribute Showing on Horizon 3

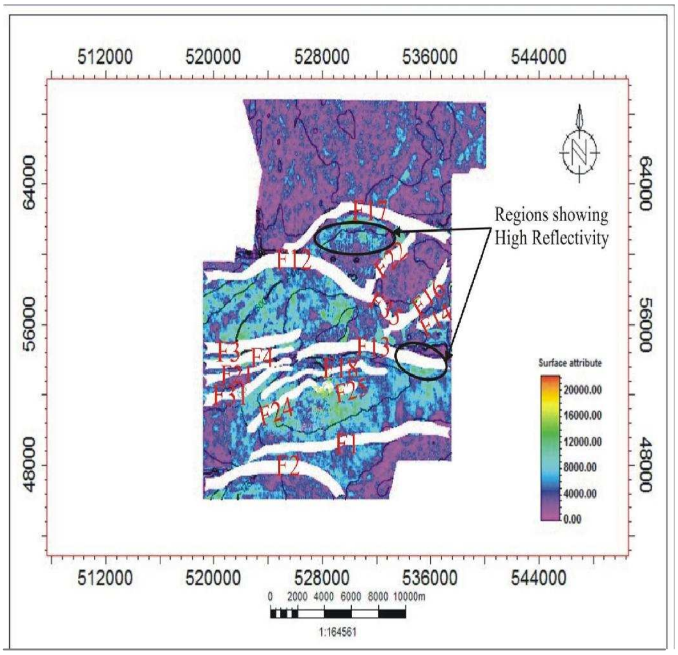


Fig. 3.11a: RMS Surface Attribute Showing on Horizon 1

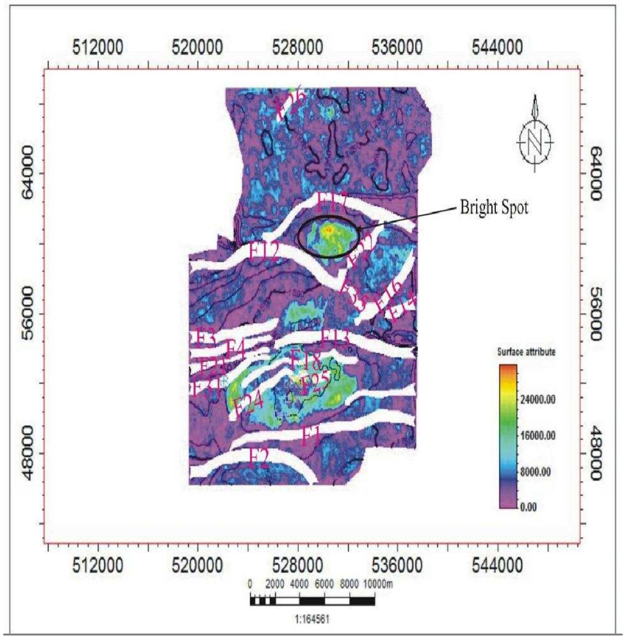


Fig. 3.11b: RMS Surface Attribute Showing on Horizon 2

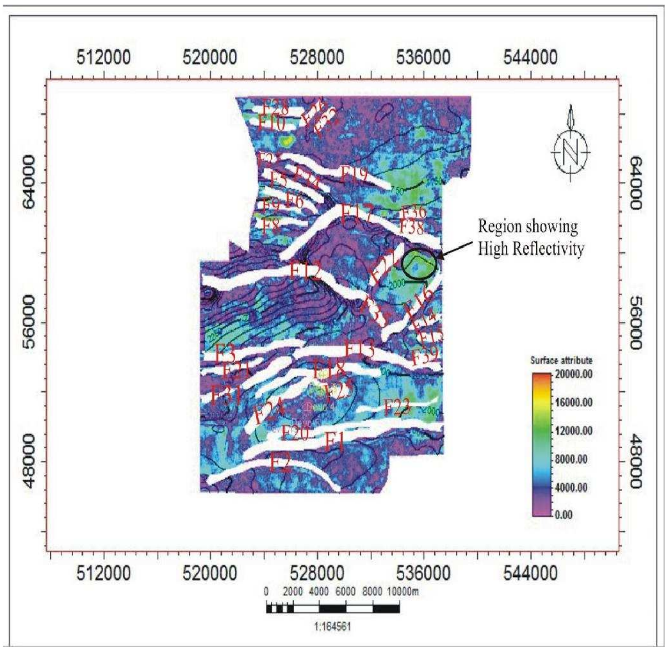


Fig. 3.11c: RMS Surface Attribute Showing on Horizon 3

3.6.1. Identified Prospects and Their Volumetric Estimations

a. Reservoir 1 (Sand 1) Prospects

Two Prospects namely P1 and P2, were identified on the Horizon 1 Depth Map. Prospect 1 (P1) is a fault-assisted closure and the area of Prospect 1 was 2341.49 Acres estimated using the fault polygon method on the seismic data. The Original-Hydrocarbon-In-Place (OHIP) was estimated as 289.9 Million of Stock Tank Barrels (MMSTB) while the Stock Tank Original Oil-In-Place (STOOIP) was estimated as 241.6 Million of Stock Tank Barrels.

b. Reservoir 2 (Sand 2) Prospects

Two Prospects namely P1 and P2 were identified on the Horizon 2 Depth Structural Map. Prospect 1 (P1) is a fault-assisted closure and the area of Prospect 1 was 2455.24 Acres estimated using the fault polygon method on the seismic data. The Original-Hydrocarbon-In-Place (OHIP) was estimated as 300.7 Million of Stock Tank Barrels (MMSTB) while the Stock Tank Original Oil-In-Place (STOOIP) was estimated as 250.6 Million of Stock Tank Barrels.
Prospect 2 (P2) is also a fault-assisted closure and the area of P2 was estimated to be 1251.64 Acres. The Original-Hydrocarbon-In-Place (OHIP) was estimated as 153.3 Million of Stock Tank Barrels (MMSTB) while the Stock Tank Original Oil-In-Place (STOOIP) was estimated as 127.7 Million of Stock Tank Barrels.

c. Reservoir 3 (Sand 3) Prospects

Two Prospects namely P1 and P2 were identified on the Horizon 3 Depth Map. Prospect 1 (P1) is a fault-assisted closure and the area of Prospect 1 was 1623.77 Acres estimated using the fault polygon method on the seismic data. The Original-Hydrocarbon-In-Place (OHIP) was estimated as 58.6 Million of Stock Tank Barrels (MMSTB) while the Stock Tank Original Oil-In-Place (STOOIP) was estimated as 48.8 Million of Stock Tank Barrels.
Prospect 2 (P2) is also a fault-assisted closure and the area of P2 was estimated to be 2101.41 Acres. The Original-Hydrocarbon-In-Place (OHIP) was estimated as 75.8 Million of Stock Tank Barrels (MMSTB) while the Stock Tank Original Oil-In-Place (STOOIP) was estimated as 63.2 Million of Stock Tank Barrels.

3.6.2. Reservoir Ranking From Volumetric Estimation

Using the volumetric estimation of the Prospects identified in “Devo” Field reservoirs, reservoir ranking of the prospects to identify reservoir with high volume of hydrocarbon was done. From the ranking shown in Figure 3.12 and Figure 3.13, it was deduced that Reservoir 1 and Reservoir 2 are the most prolific reservoirs. Thus, an exploration well may be drilled in the two reservoirs to validate it.

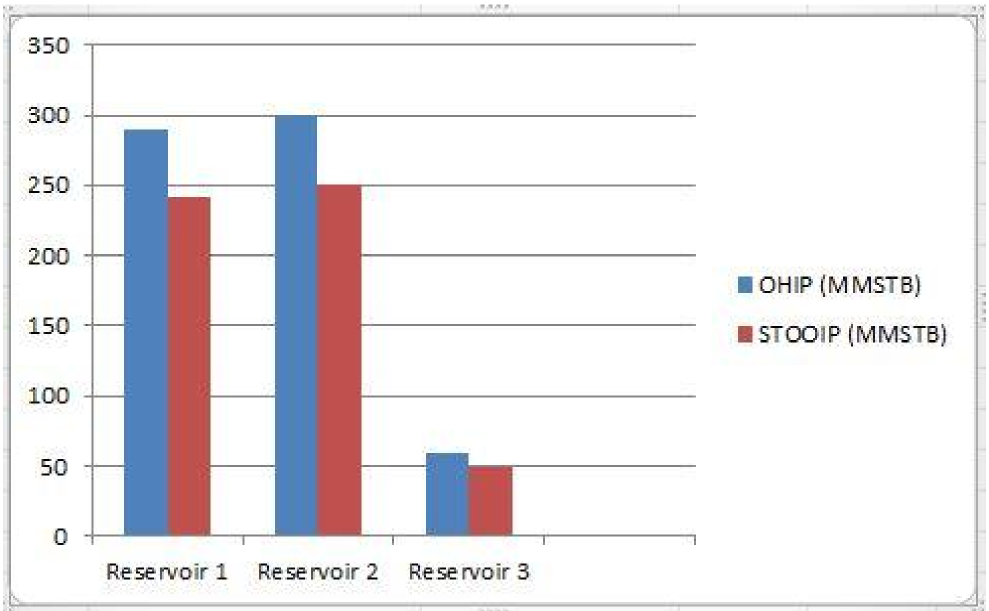


Fig. 3.12: Reservoir Ranking using Volumetric Estimation of Prospect 1

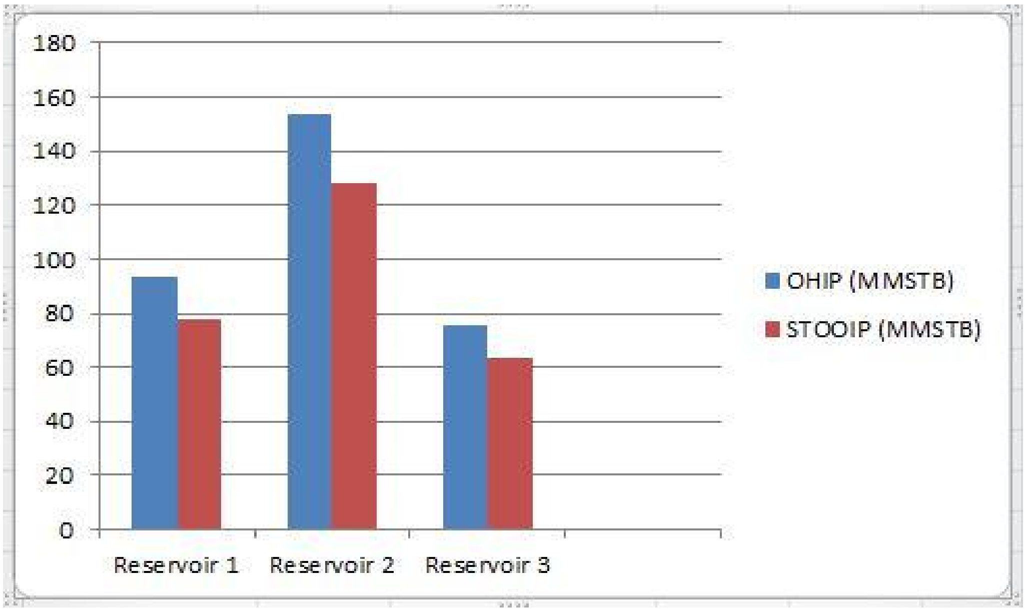


Fig. 3.13: Reservoir Ranking using Volumetric Estimation of Prospect 2

4.0. CONCLUSIONS

The study concluded that heterogeneity caused variability in petrophysical parameters but reservoir quality has not been adversely affected with the volumetric estimation of identified prospects showing that "Devo" Field has high hydrocarbon potential and can be consider for drilling.

5.0. RECOMMENDATIONS

To understand the fluid contacts, it is necessary to have available Neutron and Density Logs present for all the wells. Also to resolve reservoir heterogeneities more efficiently, the collection and interpretation of core data should be made available and the use of property or petrophysical modelling, geostatistical modelling, and heterogeneity logs should be used.

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