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RESEARCH ARTICLE

Prediction of Pore Fluid and Lithology Using Incompressibility and Rigidity, Offshore Niger Delta, Nigeria

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ABSTRACT

Pore fluid and lithology content was determined using the calculated velocity ratio and Poisson's ratio. From the analysis of velocity ratio and Poisson's ratio, the gas sand, oil sand, and brine sand were mapped out. The gas sand predicted from the rock physics analysis using lambda-mho and mu-rho was confirmed by the analysis of velocity ratio and Poisson's ratio. The analysis of velocity ratio and Poisson's ratio was used to further describe the wet sand predicted by the rock physics analysis of lambda-mho and mu-rho. The wet sand from the rock physics analysis of lambda-mho and mu-rho was predicted to comprise of oil sand and brine sand. The value of lambda-mho is between 21.74 to 25.67, for mu-rho is between 16.34 to 23.21 for Poisson's ratio is between 0.25 to 0.29 and for V_p/V_s ratio is between 1.74 to 1.83, these confirm the presence of oil sand in all the seven (7) reservoirs studied in two (2) wells, all the reservoirs fall between the Agbada region (10212.50-11741.00 ft) and have a very good net pay zone ranging from 41.50 ft to 193.00 ft in the Niger Delta region, Nigeria.

1. Introduction

Lithology basically refers to the type of rock in the Earth crust. Different kinds of rocks exist in the subsurface but not all are conducive for hydrocarbon accumulation. For a subsurface rock to be a good hydrocarbon storage, the rock should be sedimentary with pore spaces. These pore spaces can be filled with hydrocarbons (Schlumberger, 1989). Knowledge obtained about the lithology of a well can be used to determine a range of parameters including the much-needed pore fluid content. Lithology and pore fluid prediction are vital for reservoir characterization. Lithology and pore fluid prediction are very important aspects of exploration and production such as geological studies, reservoir modeling, formation evaluation, enhanced oil recovery processes, and well planning including drilling and well completion management.

Accurate determination and understanding of lithology, pore fluid, pore shapes, and sizes are fundamental to other petrophysical analysis. Determining lithology and pore fluid are key for effective exploration and production of hydrocarbon. However, accurate prediction of lithology and pore fluid is, and will continue to be, a key challenge for hydrocarbon exploration and development (Kupecz et al., 1997). The accurate determination of lithology and pore fluid aids in the accurate determination of porosity, saturation, and permeability. The economic viability of a hydrocarbon field is also reliant on the quality and accuracy of lithology and pore fluid (Hami-Eddine et al., 2015). The growing difficulty in convention (reservoir that uses the natural pressure gradient for hydrocarbon extraction) and unconventional (reservoir that requires special recovery operations outside the conventional operating practices) reservoir has made precise lithology and pore fluid prediction very essential (Hami-Eddine et al., 2015). The accurate determination of lithology and pore fluid also aid petroleum engineering decisions making.

Lithology and pore fluid can be unambiguously determined using core samples obtained from underground formation.

Core sample analysis for lithology and pore fluid prediction is expensive and usually involves vast amount of time and effort to obtain reliable information (Chang et al., 2002). Hence, this method cannot be applied to all drilled wells in a field. Also, different geoscientists may obtain inconsistent results based on their own observation and own analysis (Akinyokun et al., 2009; Serra and Abbott, 1982).

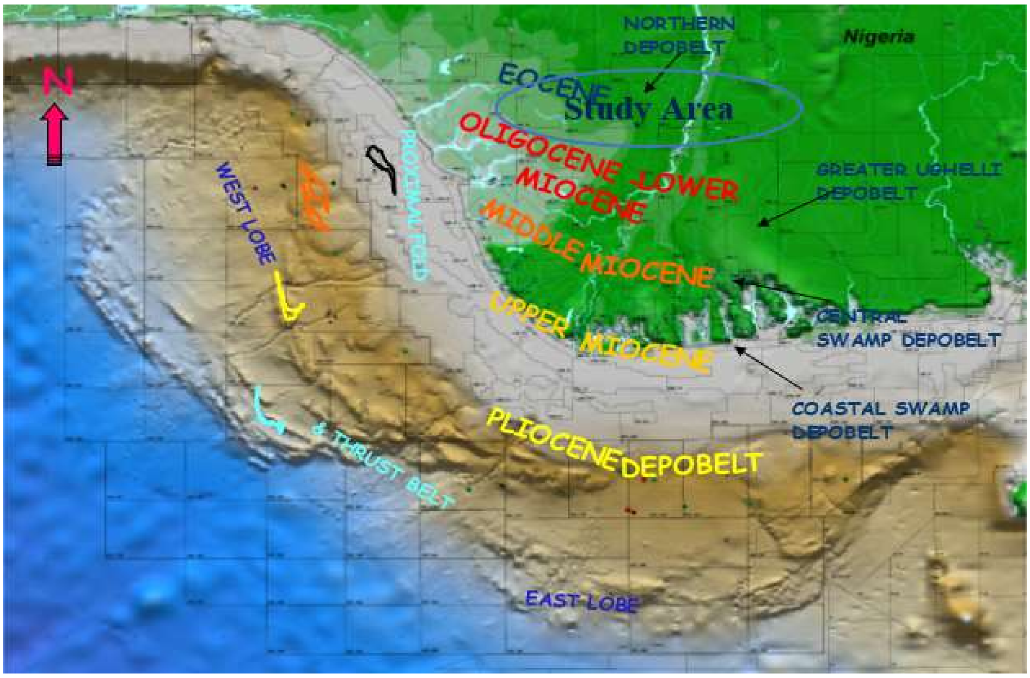

Fig. 1. Location of studied well that penetrated the Eocene succession and the Niger Delta mega-structural framework (modified from Ejedavwe et al., 2002)

Cuttings obtained from drilling operations can also be used to Considering the limitations mentioned for other methodologies, there has been a growing interest in determining lithology and pore fluid using well log data which is cheaper, more reliable, and economical compared to the other methods stated above. Well logging also offers the benefit of covering the entire geological formation of interest coupled with providing general and excellent details of the underground formation (Serra and Abbott, 1982). Brigaud et al. (1990) observed that well logs offer a better representation of in-situ conditions in a lithological unit than laboratory measurements mainly because well logs sample finite volume of rock around the well and delivers uninterrupted record with depth instead of sampling of discrete point.

Well logging is a technique used to obtain continuous detailed recording of physical parameters of a geological formation as a function of time or depth, by measuring various physical, chemical and lithological properties of the formations (Alger, 1980). Marcel and Conrad Schlumberger were the first to implement logging in the hydrocarbon industry (Schlumberger, 2000). For over a century, well logging has played a pivotal role in the detection and development of hydrocarbon resources. Well logs provide knowledge of the subsurface which can be used to predict the nature of the geological formation infiltrated during drilling.

Information obtained from well logs when appended with additional information obtained from the analysis core data, can be used to determine the depth and the nature of the formation, fluid type and extent of fluid contact, porosity and permeability, flexibility of the hydrocarbon flow rate, formation pressure, net pay, hydrocarbon in place, recoverable hydrocarbon, and other relevant information at a higher precision. Well logging is one of the essential techniques used in the hydrocarbon industry for reservoir characterization.

Well logs aid geoscientists to gain much needed knowledge about subsurface conditions. Well logs interpretation can be used in obtaining essential information and properties of a reservoir since the complete coring and core analysis of the whole pay zone is impractical (Eshimokhai and Akhirevbuku, 2012). Well log analysis and interpretation are carried out in many steps but not randomly to avoid errors. Well logs have been used to successfully predict lithology and pore fluid content of hydrocarbon reservoir.

Ogungbemi (2014) used the ratio of compressional and shear wave velocities and their travel times to predict lithology of the “Benin River Field” located in the Niger Delta Basin in Nigeria. Due to the absence of gamma ray and spontaneous potential logs, velocity ratio was used to differentiate between sand and shale. However, velocity ratio cannot be used to effectively differentiate between carbonate and shale. Hence, the need for a comprehensive lithology prediction using well logs. The main aim of the research is to use density, compressional and shear wave velocity logs as input to predict the lithology and pore fluid of a reservoir in the Niger Delta Region.

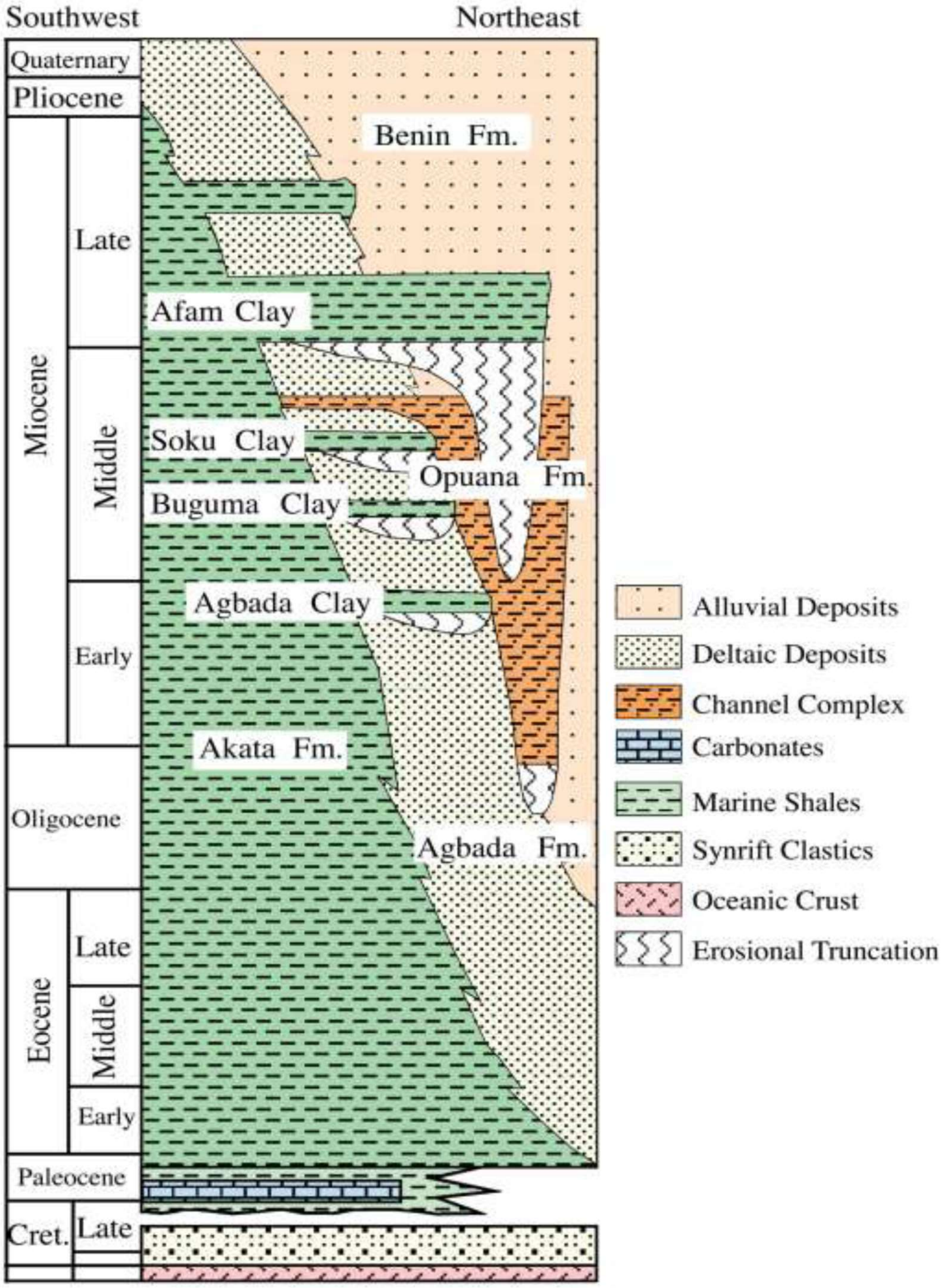

Fig. 2. Stratigraphic column showing the three formations of the Niger Delta (modified from Ejedavwe et al., 2002)

2. Location and Geological Setting of the Study Area

The Niger Delta basin is an extensional rift basin located in the Niger Delta and the Gulf of Guinea on the passive continental margin near the Western coast of Nigeria with the proven access to Cameroon, Equatorial Guinea and Sao Tome and Principle (Fig. 1).

The basin is very complex, and it carries high economic value as it contains a very productive hydrocarbon system. The Niger Delta basin is one of the largest subaerial basins in Africa. It has a subaerial area of about 75,000 km^2, a total area of 300,000 km^2, and sediment fill of 500,000 km^3. The sediment fill has a depth between 9-12 km. It is composed of several different geologic formations that indicate how this basin was formed, as well as the regional and large scale tectonic of the area. It is surrounded by many other basins that all formed from similar processes. It lies in the south westernmost part of a larger tectonic structure, the Benue trough, bounded by the Cameroon volcanic line and the transform passive continental margin.

The stratigraphy of the Niger Delta clastic wedge has been documented during oil exploration and production; most stratigraphic schemes remain proprietary to the major oil companies operating in the Niger Delta basin. The composite tertiary sequence of the Niger Delta consists, in ascending order of the Akata, Agbada and Benin formations (Fig. 2). They are composed of estimated 28,000 ft (8,535 m) of section of the approximate depocenter in the central part of the delta (Akpabio et al., 2014).

There is decrease in age basin ward, reflecting the overall regression of depositional environments within the Niger Delta clastic wedge, stratigraphic equivalent units to these three formations in eastern Nigeria. The formations reflect a gross coarsening upward progradational clastic wedge (Akpabio and Ojo, 2018), deposited in marine deltic, and fluvial environments (Inyang et al., 2015; Inyang et al., 2018). The stratigraphic distribution of these rocks is poorly understood because of the lack of drilling information and outcrops (Akpabio et al., 2014).

3. Hydrocarbon Occurrence

Most of the hydrocarbon accumulations in the Niger Delta have been found in the sandstones of the Agbada formation and are mainly trapped in roll-over anticlines fronting growth faults. The extent of the accumulation may or may not be restricted by judiciary growth faults or antithetic faults cutting the anticline. This restriction becomes more evident on the larger anticlines, which because of the size and extent of their central area, tend to form a less efficient focus for migration. (Akpabio and Ojo, 2018).

Hydrocarbon can also be obtained from the marine shale intermeddled with paralic sandstone in the Agbada formation and the marine Akata shale. Based on organic matter content and type, both the marine shale (Akata formation) and the shale interbedded with paralic sandstone (lower Agbada formation) were the source rocks for the Niger Delta oils (Agbasi et al., 2013). However, the Akata formation is the source rock volumetrically significant and whose depth of burial is consistent with the depth of the oil window (Agbasi et al., 2017).

3. Methodology

Impedance volumes were interpreted separately and then combined to estimate other geophysical parameters such as the Lame parameters, notably Lambda and Mu, respectively. These attributes optimally discriminated between facies and fluids in the study area. From the well log analysis, we discovered the reservoir sandstones have lower Lambda (incompressibility) and higher Mu (rigidity) than the shales. This method supported interpretation in this field where the reservoir sandstones and shales cannot be distinguished from the P-impedance alone. Using the simultaneous inversion results, we were able to achieve the desired discrimination by exploiting the contrast in sandstone-shale rigidity.

Most recently developed procedures for estimation of lithology and fluid content use concurrent information about both the compressional and shear properties of the reservoir rock. The shear velocity or impedance is relatively insensitive to fluid content, but the shear modulus μ is a measure of the lithology (a combination of the sand/shale ratio and the porosity) with sand having a higher μ than shale. For a given lithology/porosity, the incompressibility depends on the fluids content, with the gas having lower λ than water. Thus, a search for high quality hydrocarbon reservoirs (for instance with high porosity sand) is often equivalent to finding zones of low V_p/V_s.

The original approach by (Goodway et al., 1999; Agbasi et al., 2018) and also adopted by Okoli et al. (2018). From the well log data, we cross plotted versus for fluid discrimination or threshold type stack that isolates only the anomalous gas zone from background relationship. We took advantage of this petrophysical analysis of the well log data to determine exactly where within the cross plot different lithologies and fluid will appear, including complex lithologies. By this procedure, each lithology was defined form the well log data in terms of its $\lambda - \mu - \rho$ response. This was directly calibrated to well control to accurately represent the various lithologies and fluids present.

The analysis given by Goodway et al. (1999), relied fundamentally on V_p, V_s and ρ variations, thus masking the original modulus parameter, such as the more physical insight afforded by rigidity (μ). The link between velocity and rock properties for pore fluid detection is through the bulk modulus (K) that is embedded in V_p. However, both K and V_p have the most sensitive pore fluid indicator λ as shown by the relationships given thus:

$$V_p^2 = \frac{(\lambda+2\mu)}{\rho} \tag{1}$$

$$V_p^2 = \frac{\left(K+\left(\frac{4}{3}\right)\mu\right)}{\rho} \tag{2}$$

$$V_p^2 = \mu\rho \tag{3}$$

The emphasis here is to use moduli and density relationship to velocities (V_p, V_s) or impedances (Z_p, Z_s) given as,

P-impedance:

$$Z_p^2 = (\rho V_p)^2 \tag{4}$$

$$Z_p^2 = (\lambda + 2\mu)\rho \tag{5}$$

S-impedance:

$$Z_s^2 = (\rho V_s)^2 \tag{6}$$

$$Z_s^2 = \mu\rho \tag{7}$$

In order to extract the orthogonal Lame parameters λ and μ from the logs with measured density ρ or λ_ρ and μ_ρ from seismic without known density. Thus:

$$\lambda = V_p^2\rho - 2V_s^2\rho \quad (8)$$

$$\mu = V_s^2\rho \quad (9)$$

$$\lambda\rho = Z_p^2 - 2Z_s^2 \quad (10)$$

$$\mu\rho = Z_s^2 \quad (11)$$

Because of V_p's dependence on both λ and μ the effect of decreasing λ is a direct response of the gas porosity is almost completely offset by an increase in μ in going from capping shale to gas sand. However, for surface seismic without an independent measurement of density, the extraction of λ and μ is not possible with any certainty.

Now we demonstrate how the $\lambda - \mu - \rho$ crossplot analysis and inversion volumes were used to discriminate lithologies and fluids in the study area. The λ term or incompressibility, is sensitive to pore fluid, whereas the μ term or rigidity is sensitive to the rock matrix. It is impossible to de-couple the effects of density from λ and μ when extracting this information from seismic data. It is therefore beneficial to crossplot λ_ρ versus μ_ρ minimize the effects of density (Agbasi et al., 2017). The low penetrative ability of the gamma ray limits the area of investigation. When the density log has been correctly calibrated, it provides consistence information about the bulk density of the matrix. Table 1 are some rock matrix with the associated empirically derived density.

4. Results and Analysis

The principal step of well log analysis is to differentiate clean sand from shale using baseline on the log data and to delineate zones of interest, i.e. hydrocarbon filled clean sand. Due to the Gamma ray logs and Velocity ratio were used to infer lithology. *Vp* logs can be used to determine lithology, porosity, and pore fluid. Despite *Vp* logs been valuable, they are influenced by three separate properties of rocks, i.e. density, bulk and shear moduli, which make *Vp* ambiguous for lithology prediction. The *Vp/Vs* ratio, however, is independent of density and can be used to derive Poisson's ratio, which is a much more diagnostic lithological indicator (Kearey et al., 2002). The velocity ratio of different lithologies proposed by Castagna et al. (1985) using velocity ratio are found in Table 2.

Using a shale baseline of 1.80, an imaginary line was established to differentiate sand from shale. Deflection to the right of the baseline represents shale whilst deflection to the left of baseline represents sand, this corresponds to the gamma ray values in discriminating our sand-shale interface. Figs. 3 and 4 show sand and shale layers using velocity ratio log (from the velocity panel).

Velocity ratio is effective for distinguishing sand from shale. Lithology prediction using Lamé parameter accounts for the drawback of lithology discrimination using velocity. The Lamé parameter which is sensitive to fluid and lithology was used for the comprehensive lithology prediction of the well.

Determining reservoir properties using Lamé parameters was recognized by Goodway (2001) and Dewar and Downton (2002). Goodway (2001) encouraged the use of relationship between Lamé parameters λ (incompressibility) and μ (rigidity), and ρ (density) and how they can be used to differentiate lithology and identify gas sand. Lambda (λ) and mu (μ) are very sensitive to pore fluid and rock matrix respectively.

Table 1. Rock matrix with the associated density (Peng and Zhang, 2007)

Rock Matrix	Density (g/cm³)
Sandstone	2.0 – 2.6
Limestone	2.5 – 2.8
Dolomite	2.5 – 2.6
Shale	2.0 – 2.7

Table 2. Velocity ratio for different rock types (Castagna et al., 1985)

Range of V_p/V_s	Rock type
0.1 – 1.2	Fine grained sand
1.2 – 1.45	Medium grained sand
1.46 – 1.6	Coarse grained sand
1.6 – 1.8	Sandstone
Above 2.0	Shale or clay

Lamé parameters help interpreters to better understand rock physics. Mu-rho ($\mu\rho$) referred to as rigidity is the "resistance to strain resulting in shape change with no volume change" (Goodway et al., 1999). Mu-rho ($\mu\rho$) is very useful for discriminating lithology. The unique result from this methodology is the fact that sand has a higher mu-Rho than overlying shale. Lambda-mho ($\lambda\rho$), usually referred to as incompressibility, is useful for fluid detection and discrimination.

Research has shown that hydrocarbon filled sandstone is less dense than water filled sandstone (Klein and Philpotts, 2012). Hence, hydrocarbon filled sandstone has low Lambda-mho ($\lambda\rho$) values. Pore fluid and mineral property affect the lithology of a formation. From the Lamé parameters calculated, a cross plot of the difference Lambda-mho-Mu-Rho and density was carried out and analyzed. The bulk modulus (*KB*), shear modulus (*Mu*), Lambda-mho ($\lambda\rho$) and Mu-Rho ($\mu\rho$) are shows in the elastic parameter panel in Figs. 3 and 4. The crossplot of Lambda-mho-Mu-Rho and density for the wells are show in Fig. 5, alongside with crossplot of Lambda-mho-Mu-Rho and density, in the reservoir identified in each of the wells. From the crossplot analysis, the various lithology and fluid detected and map as gas sand, wet sand and shale.

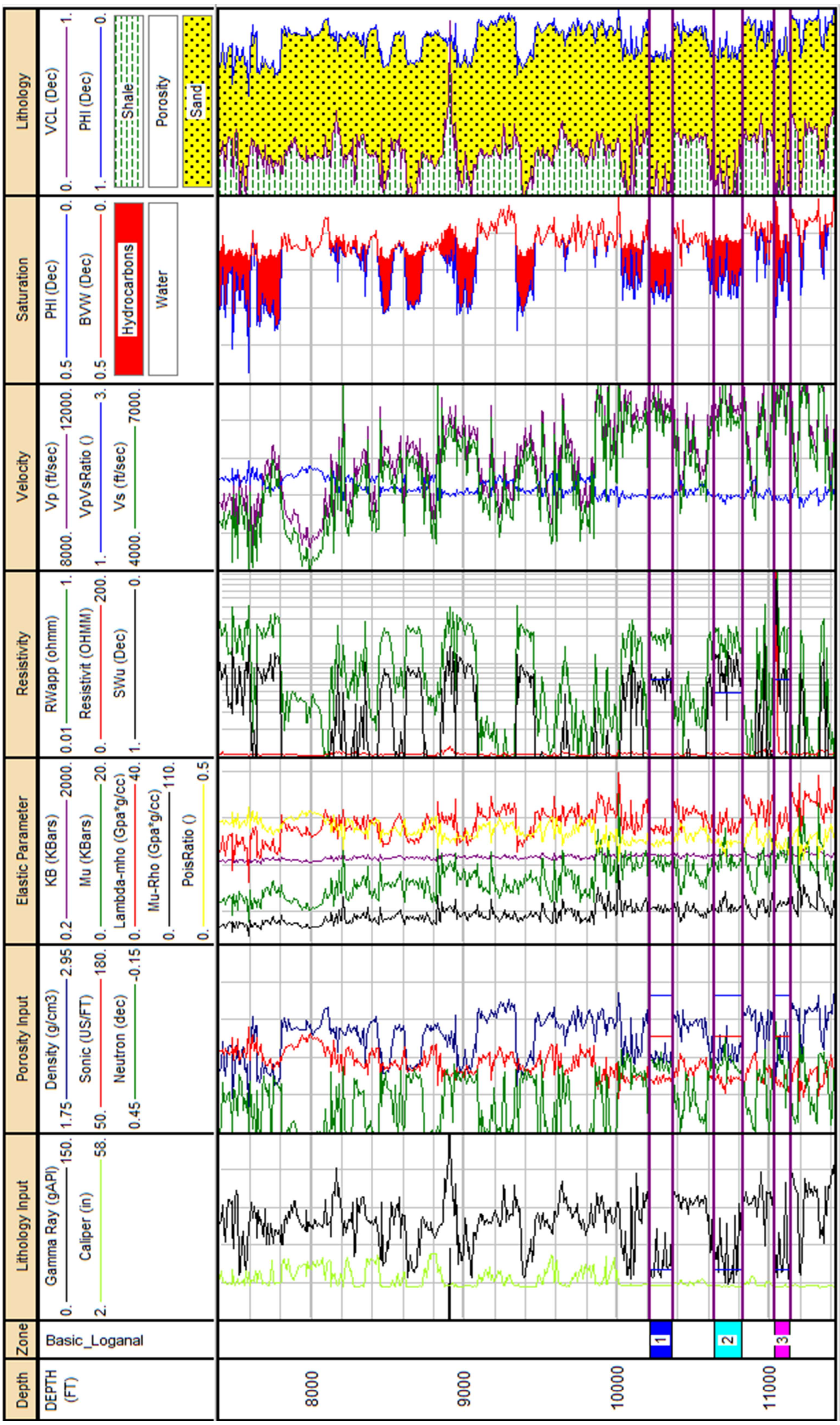

Fig. 3. Composite log suite for well AG 60 (Velocity Panel V_p/V_s Blue line)

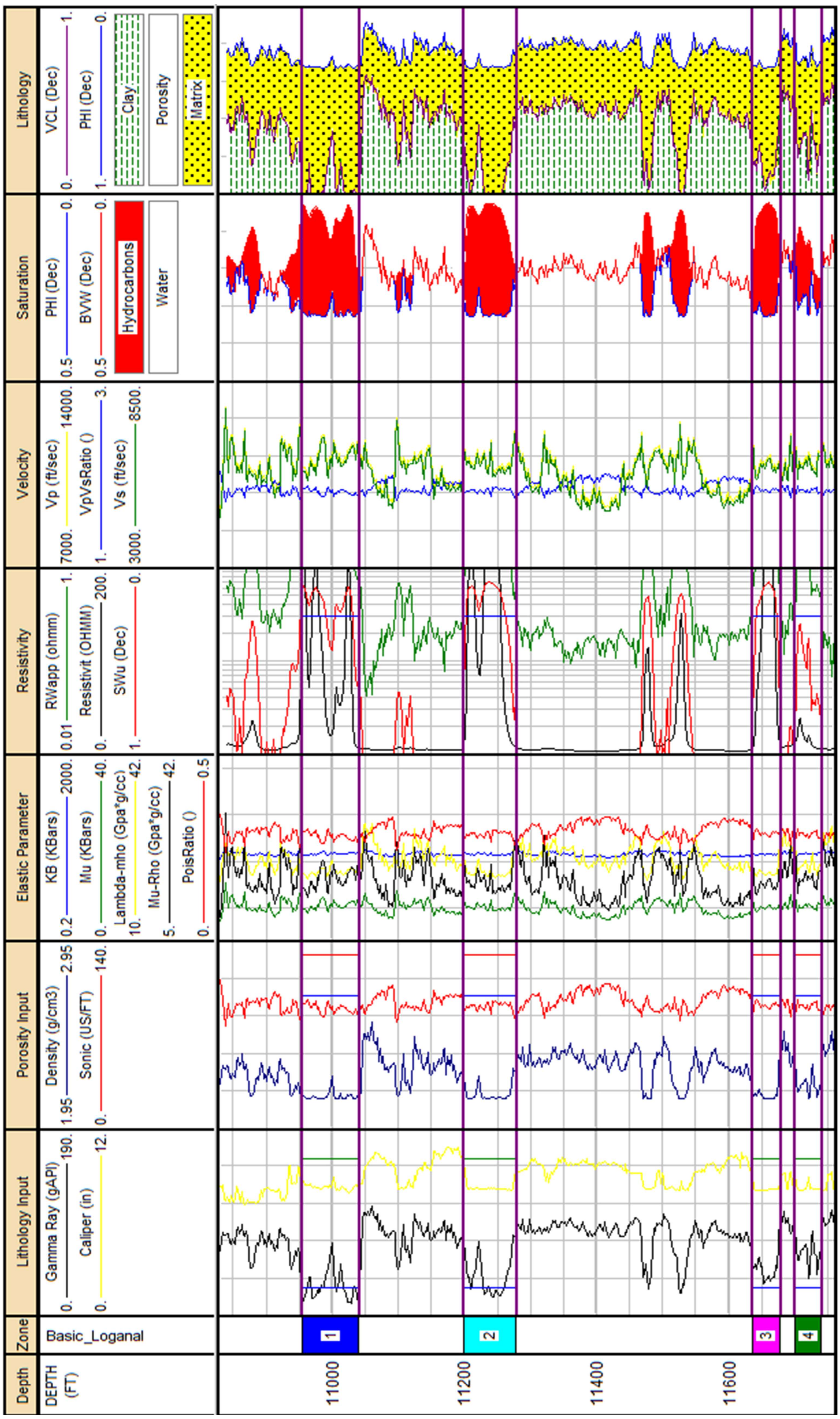

Fig. 4. Composite log suite for well AG 10 (Velocity Panel V_p/V_s Blue line)

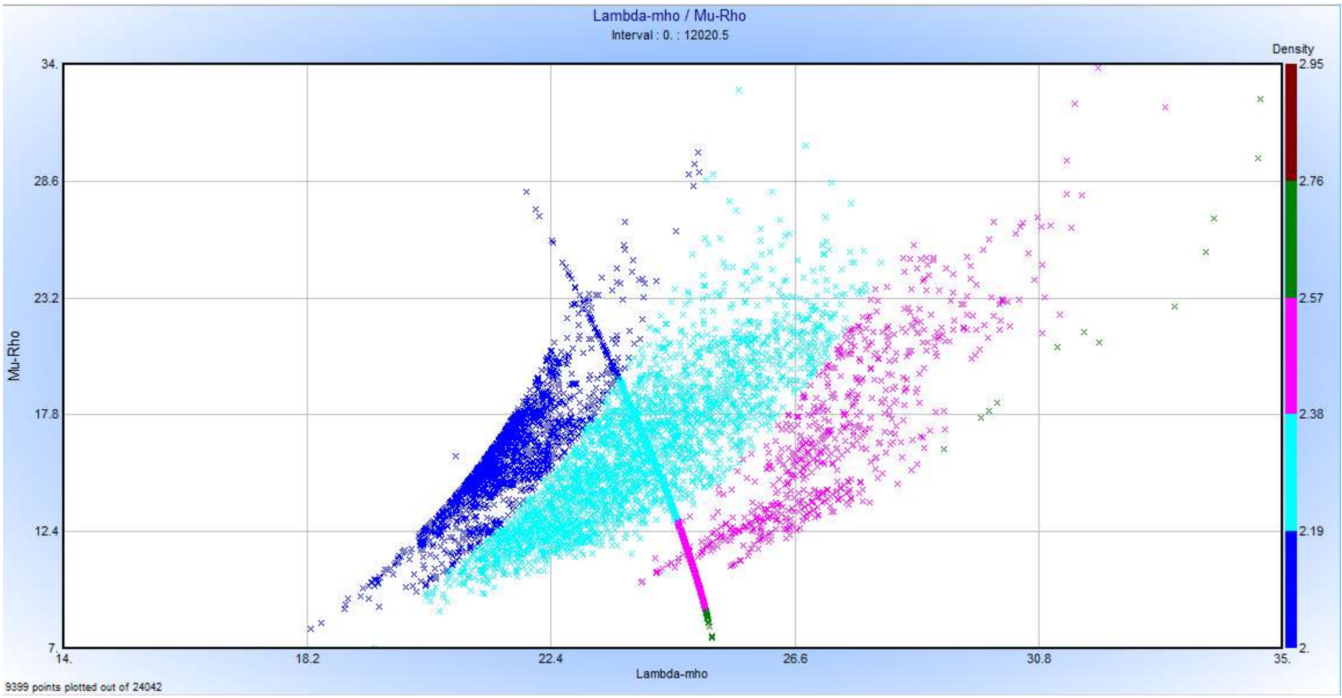

Fig. 5. Crossplot of Lambda-mho-Mu-Rho and density well AG 10

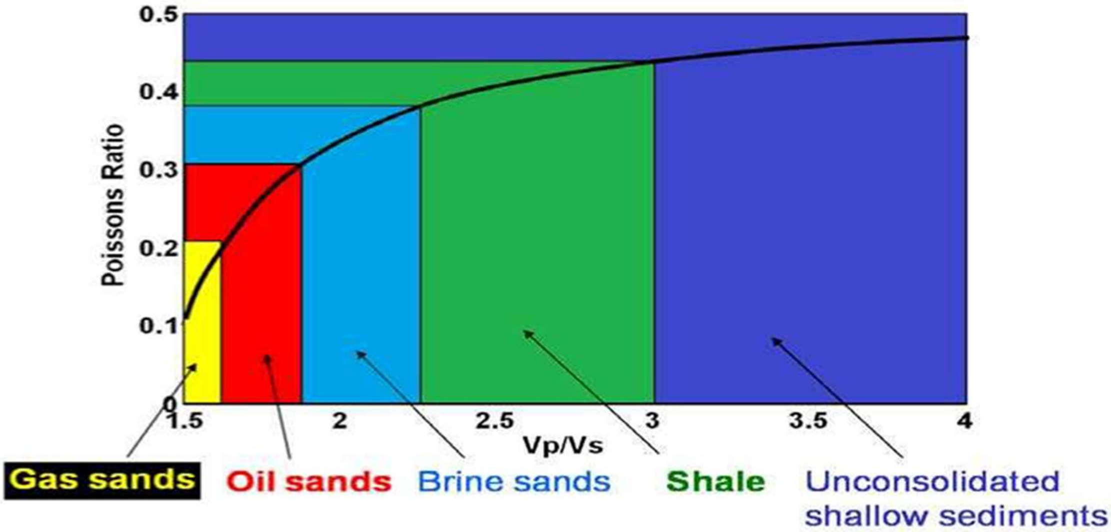

Fig. 6. Guideline for pore fluid prediction using Poisson's ratio and velocity ratio

Fig. 5 shows the various lithology and some pore fluid content. The sandstone reservoir in all the wells corresponds to a low incompressibility (lambda) but high rigidity (mu). This affirms the fact that λ, μ, and ρ are good for detecting gas filled sand, wet sand and shale.

4.1. Pore fluid prediction using *Vp/ Vs* and Poisson's ratio

A crossplot of velocity ratio and Poisson's ratio was carried out and analyzed. From the pore fluid prediction guideline shown in Fig. 6, the various pore fluid content was predicted. Pore fluid prediction is possible by analyzing the relationship existing between Poisson's ratio and velocity ratio. The crossplot of Poisson's ratio and velocity ratio is shown in Fig. 7. From the interpretation guide, it can be observed that gas and oil sand have lower Poisson's and velocity ratio compared to brine sand and shale. The gas sand, oil sand and brine sand were selected on the crossplot for the reservoirs identified in each well.

A crossplot of lambda-mho and Poisson's ratio was carried out and analyzed. Pore fluid prediction is possible by analyzing the relationship existing between Lambada-mho and velocity ratio. The crossplot of Poisson's ratio and velocity ratio is shown in Fig. 8.

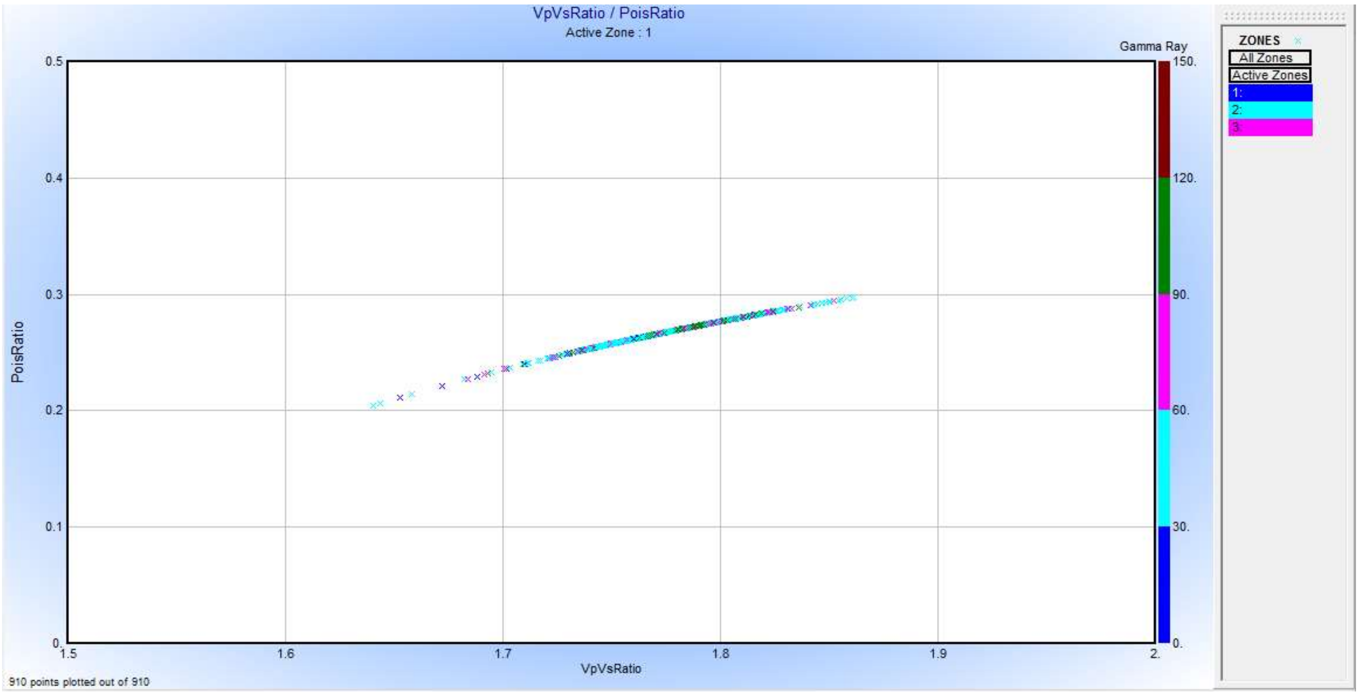

Fig. 7. A crossplot of Poisson's ratio and velocity ratio for reservoirs AG 60

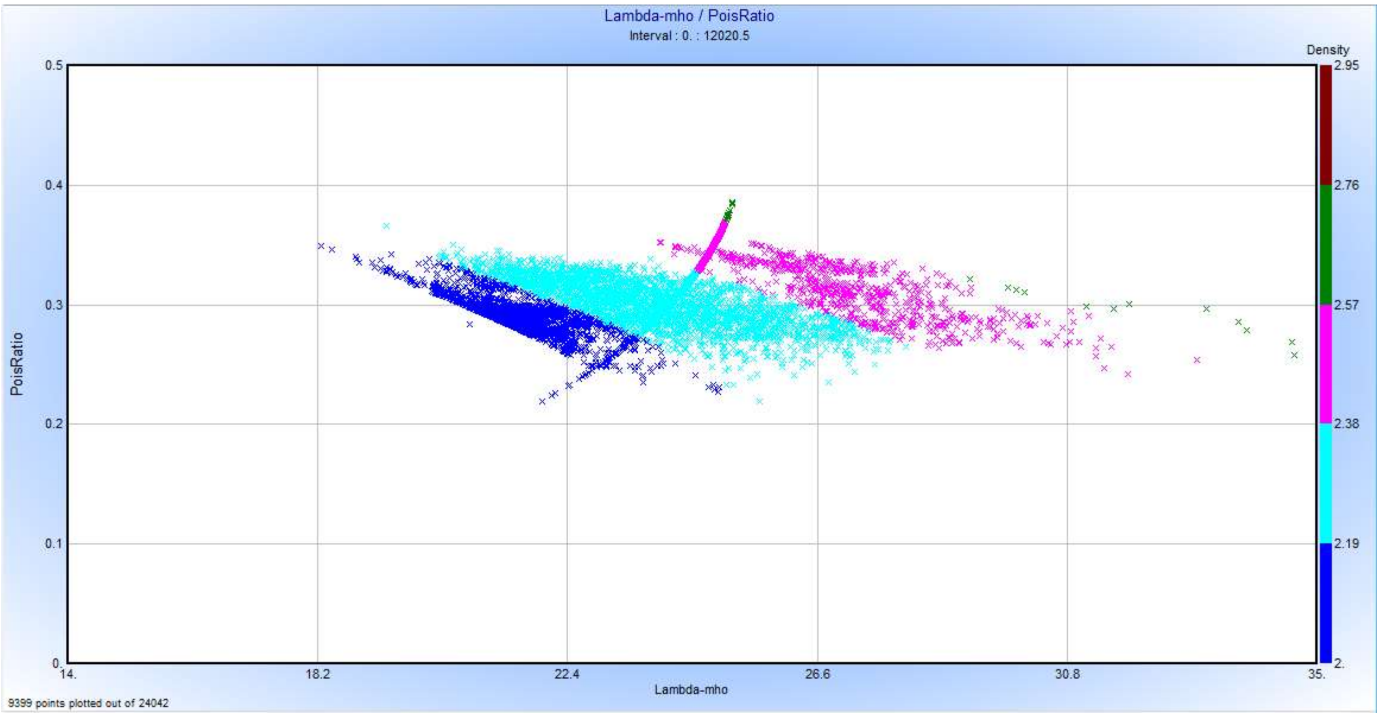

Fig. 8. Crossplot of Lambda-mho-Pois Ratio and density well AG 10

Lambda-mho ($\lambda\rho$), usually referred to as incompressibility, is useful for fluid detection and discrimination, hydrocarbon filled sandstone is less dense than water filled sandstone (Klein and Philpotts, 2012). Hence, hydrocarbon filled sandstone has low Lambda-mho ($\lambda\rho$) values. Pore fluid and mineral property affect the lithology of a formation. The crossplot of Lambda-mho-Pois Ratio and density for the wells are show in figures 4.49-4.65, alongside with crossplot of Lambda-mho-Mu-Rho and density, in the reservoir identified in each of the wells.

Table 3. Interpreted values of the reservoirs in well AG 60

AG 60		Reservoir 1 Top (ft): 10212.50, Bottom (ft): 10367.00, Net (FT): 155.00	Reservoir 2 Top (ft): 10634.50, Bottom (ft): 10827.00, Net (FT): 193.00	Reservoir 3 Top (ft): 11037.00, Bottom (ft): 11141.00, Net (FT): 104.50
Curve	**Units**	**Mean**	**Mean**	**Mean**
BVW	Dec	0.15	0.12	0.11
KB	KBars	16.01	16.45	16.85
Lambda-mho	Gpa*g/cc	24.61	25.42	25.67
Mu	KBars	8.67	9.04	9.50
Mu-Rho	Gpa*g/cc	20.88	22.10	23.21
PHI	Dec	0.25	0.23	0.23
Pois Ratio		0.27	0.27	0.26
RWapp	ohmm	0.19	0.18	1.77
SW	Dec	0.61	0.54	0.53
Vp	ft/sec	11519.68	11622.01	11832.21
VpVs Ratio		1.79	1.78	1.77
Vs	ft/sec	6455.66	6537.95	6706.98

Table 4. Interpreted values of the reservoirs in well AG 10

AG 10		Reservoir 1 Top (ft): 1091.50, Bottom (ft): 11042.50	Reservoir 2 Top (ft): 11199.50, Bottom (ft): 11274.50	Reservoir 3 Top (ft): 11635.50, Bottom (ft): 11678.00	Reservoir 4 Top (ft): 11700.00, Bottom (ft): 11741.00
Curve	**Units**	**Mean**	**Mean**	**Mean**	**Mean**
BVW	Dec	0.08	0.06	0.07	0.16
KB	KBars	14.68	14.23	14.28	14.70
Lambda-mho	Gpa*g/cc	21.89	21.74	21.90	22.94
Mu	KBars	7.64	7.12	7.14	7.42
Mu-Rho	Gpa*g/cc	17.46	16.34	16.44	17.47
PHI	Dec	0.32	0.32	0.31	0.28
Pois Ratio		0.25	0.29	0.29	0.28
RWapp	ohmm	11.07	18.74	18.69	1.26
SW	Dec	0.24	0.20	0.23	0.57
Vp	ft/sec	11223.10	10946.23	10942.85	11005.39
VpVs Ratio		1.74	1.83	1.83	1.82
Vs	ft/sec	6217.17	5994.51	5991.79	6042.09

4.2. Reservoir zone and oil water contact (OWC)

The velocity ratio was not only used to deduce lithology but also to detect the presence of hydrocarbons in pores. Velocity ratio is very sensitive to pore fluid of sedimentary rocks. In an oil layer, compressional wave velocity (*Vp*) decreases as shear wave velocity (*Vs*) increases (Bahremandi et al., 2012). Tathan (1982) realized that the velocity ratio is much lower in hydrocarbon saturated environment than the liquid saturated environment. The reduction and increase in compressional and *Vs* respectively with an increase of hydrocarbon, make velocity ratio more sensitive to fluid change than *Vp* and *Vs* individually. Velocity ratio decreases in hydrocarbon layers because density decreases in the *Vs* while bulk modulus (KB) decreases in *Vp*. This is very crucial in determining fluid and OWC. At the reservoir, a rapid reduction in velocity ratio is observed, this corresponds to a decrease of *Vp* corresponding to an increase in *Vs*. This anomaly is due to the fact that the compressional and shear wave velocities are propagated from an oil layer into a water layer.

The boundary where the rapid velocity contrast is observed is the OWC which occurs in medium to coarse grained sandstone. Tables 4 and 5 show the petrophysical and geomechanically analysis of all the reservoirs identified in the two wells.

5. Conclusion

Identification and estimation of lithology and pore fluid of a reservoir is largely based on the interpreter's capability to use available data. Well log data provide useful parameters to determine lithology and pore fluid. Petrophysics and rock physics analysis of log data were successfully applied to well log data in the Niger Delta Basin. Caliper, Sonic, Resistivity, Neutron and Density logs were used as input for this research. Interactive Petrophysics (IP) v.3.5, was developed to calculate elastic parameters such as velocity ratio, Poisson's ratio, bulk modulus shear modulus, shear velocity, compressional velocity, lambda-mho and mu-rho. Velocity ratio log was used to differentiate sand from shale to understand the general overview of the distribution of sandstone in the well. The empirical values of velocity ratio for rock types was used. After the sand and shale differentiation using velocity ratio, rock physics analysis using lambda-mho and mu-rho was carried out to determine the presence of other lithology besides sand and shale. From the calculated lambda-mho and mu-rho, a crossplot lambda-mho and mu-rho and density was analyzed. Using interpretation technique, oil sand, gas sand and brine sand were predicted from the crossplot. Pore fluid content was determined using the calculated velocity ratio and Poisson's ratio. From the analysis of velocity ratio and Poisson's ratio, the gas sand, oil sand, and brine sand were mapped out. The gas sand predicted from the rock physics analysis using lambda-mho and mu-rho was confirmed by the analysis of velocity ratio and Poisson's ratio. The analysis of velocity ratio and Poisson's ratio was used to further describe the wet sand predicted by the rock physics analysis of lambda-mho and mu-rho. The wet sand from the rock physics analysis of lambda-mho and mu-rho was predicted to comprise of oil sand and brine sand.

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