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RESEARCH ARTICLE

DETERMINATION OF POROSITY-PERMEABILITY CORRELATION WITH PRESSURE AND DEPTH IN PART OF NIGER DELTA BASIN, NIGERIA

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ABSTRACT

Porosity indicates the potentiality or fluid storage capacity of a reservoir or rock. It is the first of the two essential attributes of a reservoir. Permeability is a parameter for the recovery of hydrocarbon from the reservoir, it is required for proper reservoir evaluation, as it aids in the estimation of how much fluid can produced from the reservoir. The aim of this study is to determine porosity-permeability correlation with pressure and depth in part of Niger Delta basin using well log data. A suite of geophysical well logs comprising of gamma ray, neutron, density, spontaneous potential and sonic logs from four oil wells were used in the study. Porosity values were estimated from well log data, while permeability and pressure values were determined using empirical relations with respect to specific depth in the wells. The results of this work show that three reservoirs (reservoir sands) were identified and correlated across the four wells, each reservoir sand unit spread across the wells and differs in thickness ranging from 8ft to 155ft, with some unit occurring at greater depth than their corresponding unit.The lithostratigraphic correlation section of the wells revealed a sand – shale sequence which is a characteristic of a typical Niger Delta formation. The average porosity, permeability, pressure and depth values for the four wells range from 0.001 to 0.309, 34.999mD to 306.360mD, 61926.863psi to 109928.054psi and 3000ft to 4450ft respectively. The analysis of the wells show that wells OTIG9 and OTIG11 have better reservoirs indicating high potentiality and productivity due to their more porous and permeable nature, reflecting well sorted coarse grained sandstone and linearity in the relationship between porosity, permeability, pressure and depth. The reservoir of well OTIG7 is the least porous but most permeable, thus is highly productive but less potential. The reservoir of OTIG2 has moderate potentiality and good productivity, hence is said to have average production capacity. The results of this work can be used as an evaluation tool for reservoir engineering activities, structural engineering, well stability analysis, blowout and lost circulation prevention.

KEYWORDS

Porosity, Permeability, Overburden pressure, Lithology, Well log.

1. INTRODUCTION

The measure of the void space in a rock is defined as its porosity, while the measure of the ability of the rock to transmit fluid is its permeability. The knowledge of these two parameters is essential before questions concerning types of fluid, amount of fluid, rate of fluid flow and fluid recovery estimates can be answered (Djebbar and Erle, 2004). The flow of fluid through rock materials is governed by properties such as the porous nature, interconnectivity of the pores, as well as the properties of the following fluid (Saar, 1998). A potential reservoir is one whose rocks possess enough porosity and permeability that can enable oil and gas flow through it. Porosity is the capacity of a reservoir rock to contain hydrocarbon (Tarek, 2006). This implies that it is a measurement of the void spaces between the grains in a rock formation (Ma and Morrow, 1996). Permeability, however is a different parameter which measures the flowing capacity of the rock. In more specific terms, explains that it is the measurement of the rock's ability to transmit fluid under differential pressure (Buryakovsky, et al., 2012).

A general trend of permeability increasing with porosity can be seen in most cases, especially in most consolidated sandstone and carbonate reservoirs, as the reverse is seen in unconsolidated clay. A reservoir or rock can have very high porosity without having any permeability at all, as in the case of pumice stone, clays and shales. A case of high permeability with low porosity might also be true, such as in micro-fractured carbonates (Djebbar and Erle, 2004). Overburden pressure (also referred

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to as Geostatic or Lithostatic pressure) is the pressure due to the weight of overlying rocks on a formation. When overburden pressure exceeds pore pressure, the formation is compacted causing a reduction in porosity and hence permeability (Baker and Jensen, 2015). Porosity and permeability depends on geostatic pressure and compaction as a function of depth, this implies that under ideal situation, porosity decreases with depth of burial or geologic age as a result of the effect of compaction resulting from overburden pressure, but in some reservoirs or formations, due to pressure inversion, there can be observance of inversion in porosity as well as permeability.

Overpressure is the term used to describe subsurface pressures that significantly exceed the hydrostatic pressure. This implies that the flow of porewater to the surface during compaction is resisted to a considerable degree, so that the pressure gradients are increased in the least permeable part of the sediments. (Bjorlykke, 1993). Abnormal geopressures (above or below the normal gradient) are found in many hydrocarbon producing reservoirs. While the origin of these pressures is not understood completely, abnormal pressure development is usually attributed to the effects of compaction, diagenetic activities, differential density and fluid migration (Bourgoyne et al., 1986). Electrical well logging was introduced into the oil and gas (petroleum) industry over a century, devices have been developed and are widely used. As the knowledge of well logging advanced, the act of interpreting the data also advanced. Presently, the detailed analysis of a carefully chosen suite of wire line services provides a method of deriving or inferring accurate values for the porosity, permeability, hydrocarbon and water saturations as well as the lithology of the rocks in the reservoir (Schulumberger, 1989).

2. Geology 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 as shown in figure 1. It has proven access to Cameroon, Equatorial Guinea and Sao Tome and Principe. The basin is a very complex one and contains a very productive petroleum system (Tuttle et al., 2015). The Niger Delta Basin is one of the largest surface basins in Africa with a subaerial area of about 75,000km^2, a total area of about 300,000km^2 and a sediment fill of about 500,000km^3. The sediment fill has a depth between 9 to 12km (Fatoke, 2010). It comprised of three major structural geologic formations, namely Akata, Agbada and Benin formations that indicate how the basin was formed as shown in figure 2.

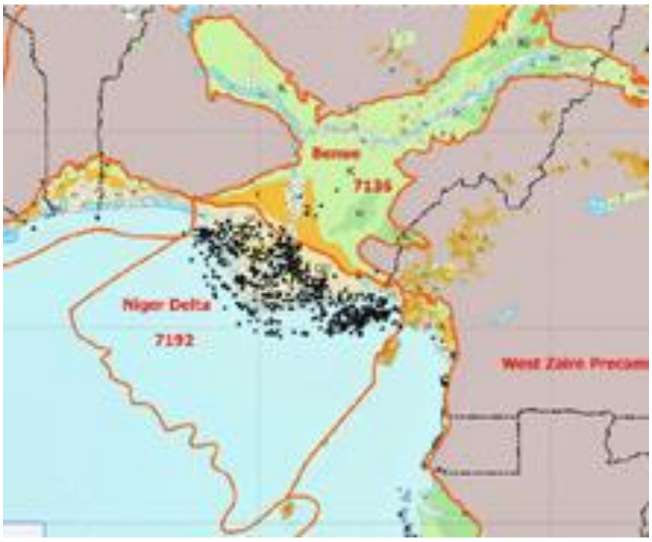

Figure 1: Geologic map of Niger Delta Basin (Short and Stauble, 1967)

2.1 Basin Formation

The Niger Delta Basin was formed as a result of a failed rift junction during the separation of the South American plate and the African plate. Rifting in this basin started in the late Jurassic and ended in the mid Cretaceous era. As rifting continued, many faults were formed. Syn-rift sands and shales were deposited in the late Cretaceous era, this indicates that the shoreline regressed during this time. At the beginning of the Paleocene era, there was a significant shoreline transgression (Fatoke, 2010). During the Paleocene era, the Akata formation was deposited, followed by Agbada formation during the Eoscene era. This loading caused the underlying shale Akata formation to be squeezed into shale diapirs. Then in the Oligocene era, the Benin formation was deposited, which is still being deposited today. The basin is divided into different zones due to its tectonic structure (Tuttle et al., 2015). There is an extensional zone which lies on the continental shelf, caused by the thickened crust. There is a transition zone and a contraction, which lies in the deep-sea part of the basin.

2.1.1 *Akata Formation*

The Akata Formation is Paleocene in age, it comprised of thick shales, turbidite sands, and small amount of silt and clay. The clay content resulted in it being a ductile shale formation which was squeezed into shale diapirs in the basin. The formation is estimated to be about 7,000 meters thick and formed during lowstands in relative sea level and anoxic conditions (Tuttle et al., 2015). The Akata Formation is part of the petroleum system located in the Niger Delta Basin, of Nigeria at the Gulf of Guinea, Atlantic Ocean. According to (Owoyemi, 2004), the upper Akata Formation is a primary source rock, providing Type II/III kerogen and a potential target in deep water offshore. The clays are typically over-pressured due to the absence of enough porous sediments during compaction and are about 9,000ft vertical depth below mean sea level (Tuttle et al., 2018).

2.1.2 *Agbada Formation*

The Agbada Formation dates back to Eocene era, it is marine facies defined by fresh water and deep-sea characteristics. It is the major oil and natural gas bearing zone in the basin. The hydrocarbon in this formation formed when the rocks became subaerial and was covered in a marsh type environment rich in organic content. It is estimated to be about 3,700 meters thick (Tuttle et al., 2015).

2.1.3 *Benin Formation*

The Benin Formation is Oligocene and younger in age. It comprised of continental flood plain sands and alluvial deposits and estimated to be about 2,000 meters thick (Tuttle et al., 2015).

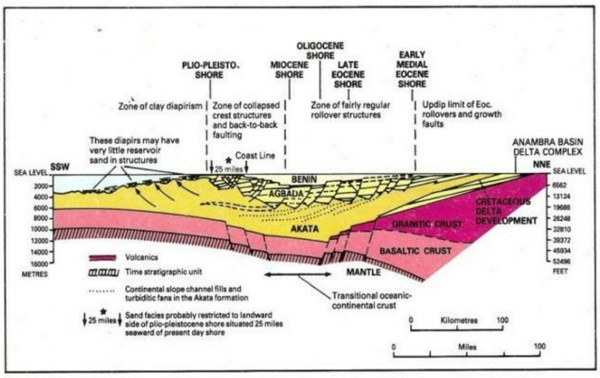

Figure 2: Akata, Agbada and Benin Formations. (Short and Stauble, 1967)

3. Materials and Methods

3.1 Materials

Gamma ray (GR), Spontaneous potential (SP), sonic, neutron and density logs obtained from four exploratory wells were used for this study. Petrophysical parameters (porosity and permeability) and pressure which aid in reservoir characterization were computed at various depths and reservoir units delineated. Secondary data set comprising of gamma ray, spontaneous potential, sonic, neutron and density logs values obtained from Shell Petroleum Development Company (SPDC) were used for this study. Petrel software was used in this study to analyze, interpret the data sets and for reservoir or well parameters correlation.

3.2 Methods

To achieve the aim of this study, data set from four well-logs were used to evaluate the parameters of interest (porosity, permeability and pressure values) at different depth in the well.
Five stages which include loading of well log data, editing of bad traces, determination of petrophysical parameters, litho-strstigraphic correlation and cluster analysis are involved in the method used for this study.

3.2.1 Loading of well log data

The data set from the four well logs were quality checked, loaded into the petrel software, analyzed and interpreted.

3.2.2 Editing of bad traces

The log data were normalized (corrected), de-spiked and filtered in order to remove anomalous data points, which may have resulted from gas or shale effect.

3.2.3 Determination of Petrophysical Parameters

3.2.3.1 Determination of lithology

Gamma ray (GR) log as shown in figure 3 was used to delineate the lithology of the formation into shale and sandstone beds at the pre-determined depth intervals. The gamma ray (GR) log values in American Petroleum Institute (API) ranges from 0.00 to 150.0. As the log reading tends towards the higher values (shale-line), the formation becomes more shaly while as it tends towards the lower values (sand-line), the formation becomes sandier. According to determine the percentage volume of shale and sand in the well or reservoir, the equations below were used (Schlumberger, 2000):

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

$$V_{sh} = 0.33(2^{2I_{GR}} - 1.0) \quad (2)$$

$$\%Shale = V_{sh} \times 100\% \quad (3)$$

$$\%Sand = 100 - \%Shale \quad (4)$$

Where $I_{GR} = Gamma\ ray\ index$

$\%Shale$ = Percentage volume of shale
$\%Sand$ = Percentage volume of sand
GR_{log}= Gamma ray log reading of the formation
GR_{min}= Gamma ray log reading in sand zone.
GR_{max}= Gamma ray log reading in shale zone.

3.2.3.2 Determination of porosity, Φ

Density log was used to determine the porosity values of the wells by applying the equation below:

$$\Phi_D = \frac{P_{mat} - P_b}{P_{mat} - P_f} \quad (5)$$

Where Φ_D= Porosity derived from density log.
P_{mat}= Density of matrix.
P_b= Formation bulk density read directly for the log.
P_f= Formation fluid density.

3.2.3.3 Determination of permeability, K

In this study, permeability values of the reservoir were determined using Carman-Kozeny's correlation equation (1927) which relates the porosity, permeability and radius of the reservoir as:

$$K = \frac{\Phi r^3}{8} \quad (6)$$

Where K = Permeability of reservoir
Φ = Porosity of reservoir
r = Radius of reservoir

3.2.3.4 Determination of overburden or geostatic pressure

Under ideal hydrostatic conditions, according to Haney et al (2007), geostatic pressure (effective stress) increases with depth and its values for the wells were determined using empirical relation below:

$$P = \rho_f g d \quad (7)$$

Where P = Geostatic pressure
ρ_f= Formation bulk density read from log
g = Gravitational acceleration
d = depth

3.2.4 Litho-stratigraphical correlation

Litho-stratigraphic sections were identified on the logs and correlated across the four wells for proper (efficient and effective) lithology delineation.

3.2.5 Cluster analysis

Cross plot analysis was used to determine well parameters that better differentiate the reservoirs and show their relationships. They include porosity-permeability, porosity-pressure, porosity-depth, permeability-pressure, permeability-depth, and pressure-depth as shown in figures 7 to 30.

4. RESULTS AND DISCUSSION

4.1 Display of Well Logs

The study area consists of four wells which are OTIG 2, OTIG 7, OTIG 9 and OTIG 11. The logs in these wells are shown in Table 5. The various logs in these wells are good to successfully carry out this research. From Table 5, it is observed that sonic log was not applied in OTIG 11, but this cannot stop the achievement of the aim of this research, as the porosity values in that well can be estimated from Density log.

4.2 Petrophysical Parameters Evaluation

The results of this work are presented in Tables 1 to 4 which shows the values of porosity, permeability, pressure and depth for the four wells and in Figures 7 to 30 which shows the graphs (cross plots) of porosity-permeability, porosity-pressure, porosity-depth, permeability-pressure, permeability-depth, and pressure-depth for the wells.

Table 1: Petrophysical parameters for well OTIG 2

S/N	Depth (ft)	Porosity	Permeability (mD)	Pressure (psi)
1	3000	0.126	149.606	66829.109
2	3050	0.142	138.131	68502.648
3	3100	0.084	88.151	72547.984
4	3150	0.204	228.127	66813.328
5	3200	0.115	108.905	73518.406
6	3250	0.280	213.066	69537.203
7	3300	0.095	82.729	77638.226
8	3350	0.138	141.835	75047.406
9	3400	0.140	118.287	77523.312
10	3450	0.151	135.636	77626.171
11	3500	0.163	121.165	79620.679
12	3550	0.204	136.265	79838.546
13	3600	0.204	162.335	79501.289
14	3650	0.261	197.345	78831.343
15	3700	0.176	191.144	80213.945
16	3750	0.065	110.899	86012.085
17	3800	0.080	71.263	90490.359
18	3850	0.201	136.540	86568.359
19	3900	0.178	139.407	87516.093
20	3950	0.073	65.671	94678.109
21	4000	0.034	55.643	97114.320
22	4050	0.041	53.749	98638.546
23	4100	0.058	57.948	99228.125
24	4150	0.050	61.452	99980.343
25	4200	0.136	76.724	99425.156
26	4250	0.143	104.989	97964.789
27	4300	0.155	89.926	100461.757
28	4350	0.011	34.999	109928.054

Table 2: Petrophysical parameters for well OTIG 7

S/N	Depth (ft)	Porosity	Permeability (mD)	Pressure (psi)
1	3000	0.104	132.968	67633.593
2	3050	0.099	65.761	73123.859
3	3100	0.101	73.158	73664.796
4	3150	0.177	150.269	70141.335
5	3200	0.029	85.497	75083.054
6	3250	0.236	178.402	71024.609
7	3300	0.001	187.413	71718.343
8	3350	0.102	105.207	77208.414
9	3400	0.074	92.726	79230.132
10	3450	0.070	135.995	77606.171
11	3500	0.213	306.360	71211.539
12	3550	0.268	203.273	76396.843
13	3600	0.241	185.020	78344.578
14	3650	0.229	150.247	81272.960
15	3700	0.123	124.032	83982.187
16	3750	0.016	84.439	88081.476
17	3800	0.122	83.954	89295.687
18	3850	0.235	159.490	85184.812
19	3900	0.171	144.246	87206.539
20	3950	0.184	144.980	90298.351

Table 3: Petrophysical parameters for well OTIG 9

S/N	Depth (ft)	Porosity	Permeability (mD)	Pressure (psi)
1	3000	0.301	208.089	61926.863
2	3050	0.109	102.098	70479.054
3	3100	0.309	255.904	64750.734
4	3150	0.056	78.334	74447.679
5	3200	0.225	159.094	70821.875
6	3250	0.092	74.708	77128.648
7	3300	0.046	69.524	78740.101
8	3350	0.281	216.685	71524.328
9	3400	0.068	94.568	79098.390
10	3450	0.071	71.356	82147.789
11	3500	0.127	107.21	80540.437
12	3550	0.040	68.680	84743.570
13	3600	0.215	148.466	80258.859
14	3650	-	-	-

Table 4: Petrophysical parameters for well OTIG 11

S/N	Depth (ft)	Porosity	Permeability (mD)	Pressure (psi)
1	3000	0.126	109.853	68870.750
2	3050	0.097	122.454	69312.679
3	3100	0.070	81.252	73041.500
4	3150	0.048	109.769	68728.906
5	3200	0.275	206.586	73986.437
6	3250	0.102	120.559	71012.710
7	3300	0.254	203.373	74325.257
8	3350	0.231	155.488	73233.171
9	3400	0.271	201.807	74800.437
10	3450	0.098	122.542	80254.578
11	3500	0.061	111.277	82088.281
12	3550	0.087	101.320	77258.929
13	3600	0.278	207.913	84661.015
14	3650	0.132	98.090	81046.234
15	3700	0.251	174.762	89285.132
16	3750	0.021	71.403	82831.351
17	3800	0.111	182.433	82924.867
18	3850	-	202.019	86907.507
19	3900	-	151.400	90707.125
20	3950	-	109.497	87871.343
21	4000	-	170.335	87728.062
22	4050	-	192.521	95548.093
23	4100	-	92.627	97697.195
24	4150	-	82.101	100410.828
25	4200	-	67.782	102445.796
26	4250	-	61.039	102445.796
27	4300	-	-	-
28	4350	-	-	-
29	4000	-	-	-
30	4450	-	-	-

4.3 Litho-Stratigraphic Correlation

Figure 3 shows the litho-stratigraphic correlation of the wells. The wells were analyzed in terms of lithology from gamma ray log and shows a sand-shale sequence which is a characteristic of a typical Niger Delta formation as shown in figure 2. Shale lithologies were identified by high gamma ray value (reading), whereas sand lithologies were identified by low gamma ray values.

4.4 Reservoir Identification

Three reservoirs are considered in this study, and they are Sand A, Sand B, and Sand C. Figure 4 shows the three reservoirs in OTIG 2 and OTIG 7. Figure 5 shows the three reservoirs in OTIG 9, while Figure 6 shows the three reservoirs in OTIG 11.

Table 5: Log Types Present in each Well

Well	SP log	Gamma ray log	Density log	Neutron log	Sonic log
OTIG 2	Yes	Yes	Yes	Yes	Yes
OTIG 7	Yes	Yes	Yes	Yes	Yes
OTIG 9	Yes	Yes	Yes	Yes	Yes
OTIG 11	Yes	Yes	Yes	Yes	No

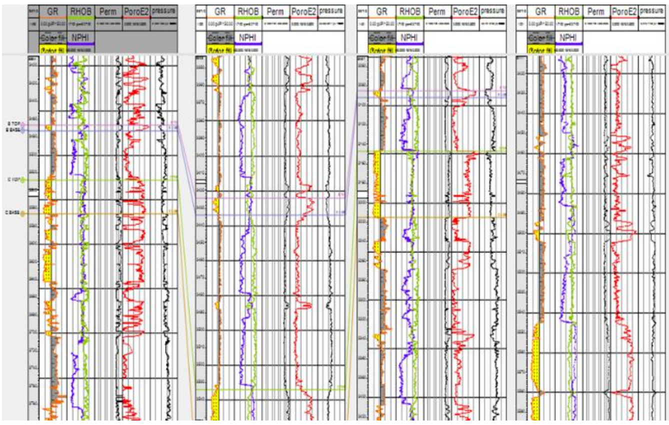

Figure 3: Correlation of the various Wells.

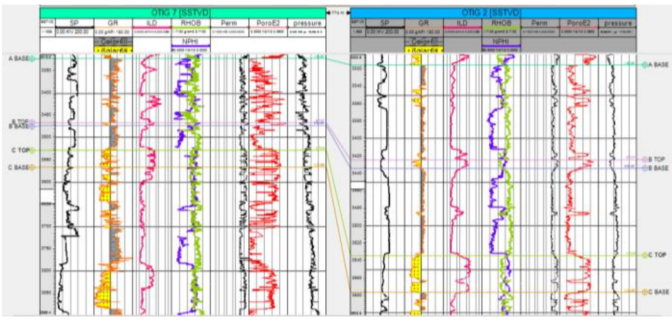

Figure 4: Display of the three reservoirs in Wells OTIG 7 and OTIG 2.

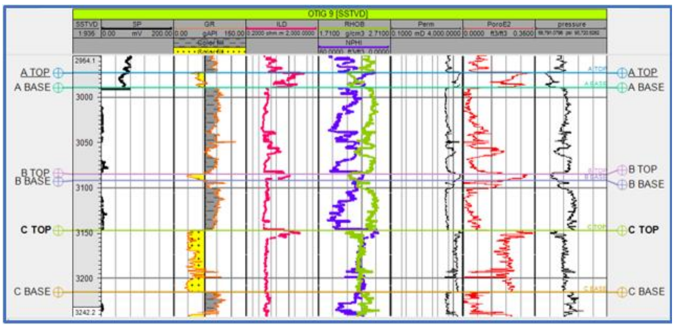

Figure 5: Display of the three reservoirs in Well OTIG 9.

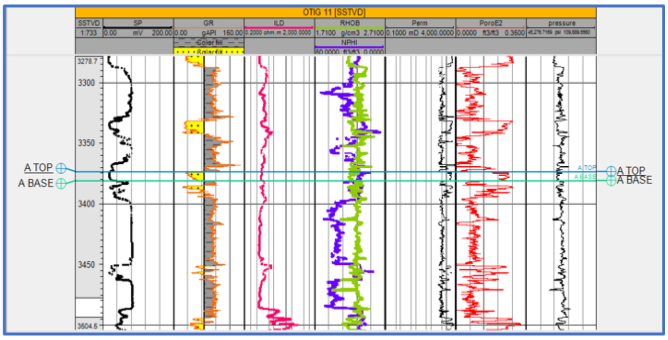

Figure 6: Display of the three reservoirs in Well OTIG 11.

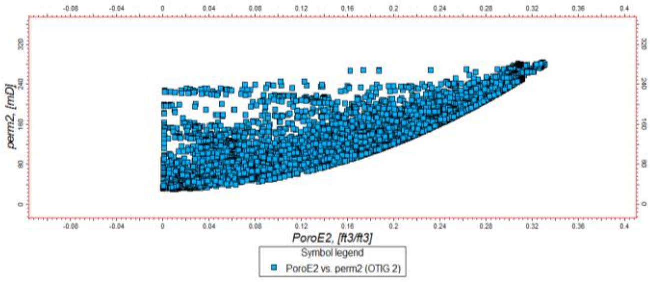

Figure 7: Display of Porosity - Permeability Relationship for OTIG 2.

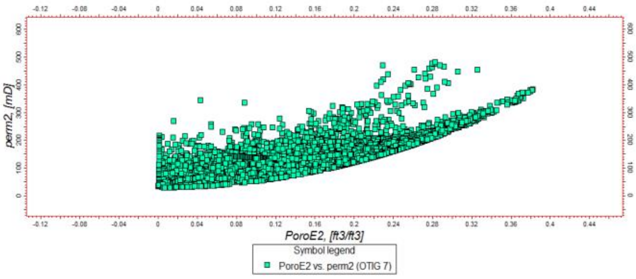

Figure 8: Display of Porosity - Permeability Relationship for OTIG 7.

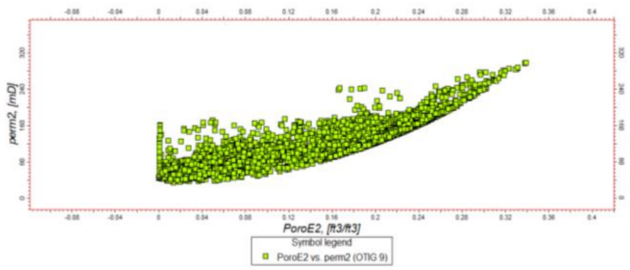

Figure 9: Display of Porosity - Permeability Relationship for OTIG 9.

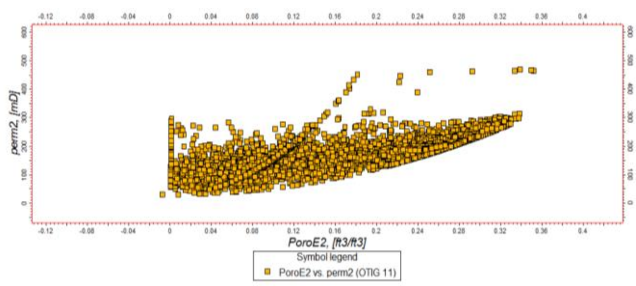

Figure 10: Display of Porosity - Permeability Relationship for OTIG 11.

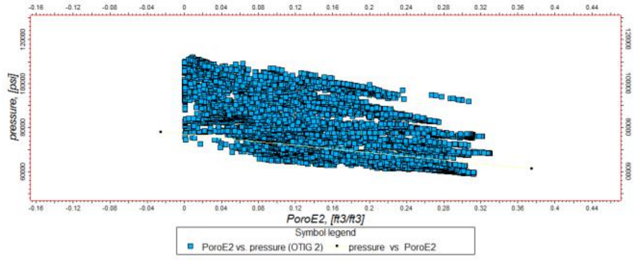

Figure 11: Display of Pressure - Porosity Relationship for OTIG 2.

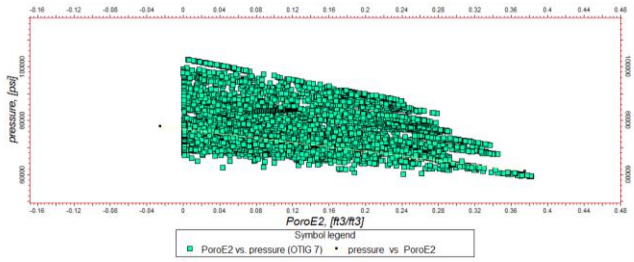

Figure 12: Display of Pressure - Porosity Relationship for OTIG 7.

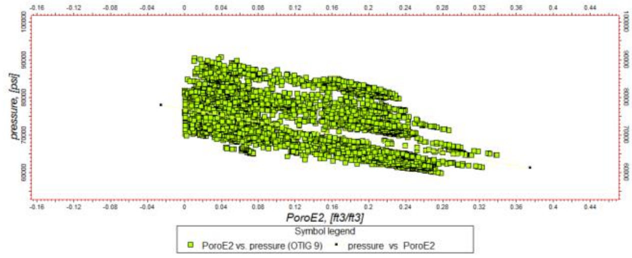

Figure 13: Display of Pressure - Porosity Relationship for OTIG 9.

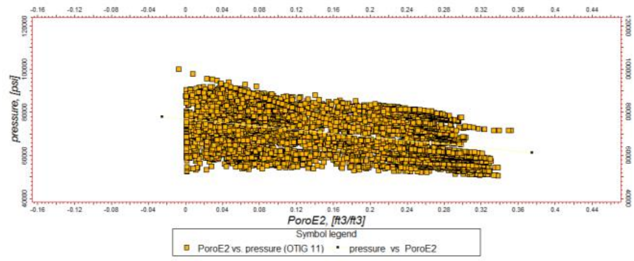

Figure 14: Display of Pressure - Porosity Relationship for OTIG 11.

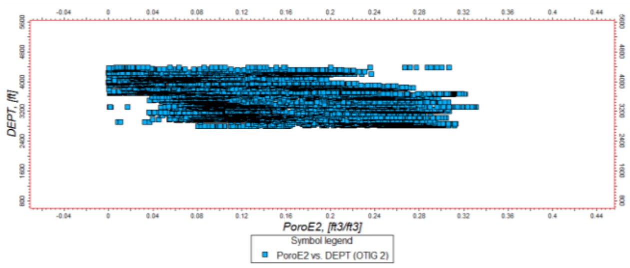

Figure 15: Display of Depth – Porosity Relationship for OTIG 2

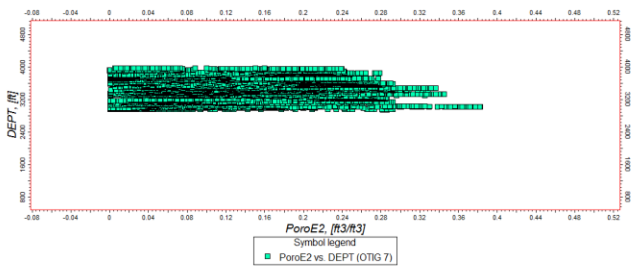

Figure 16: Display of Depth - Porosity Relationship for OTIG 7.

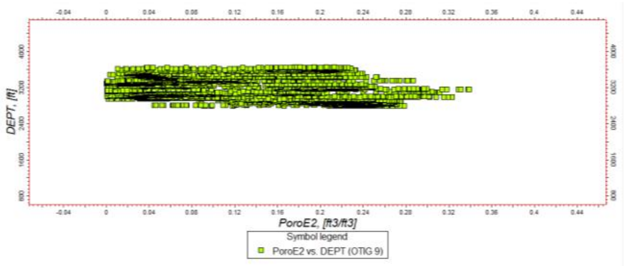

Figure 17: Display of Depth - Porosity Relationship for OTIG 9.

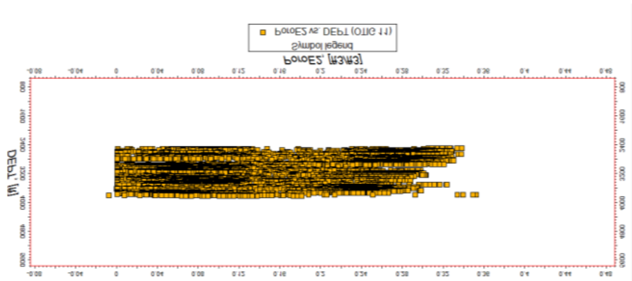

Figure 18: Display of Depth - Porosity Relationship for OTIG 11.

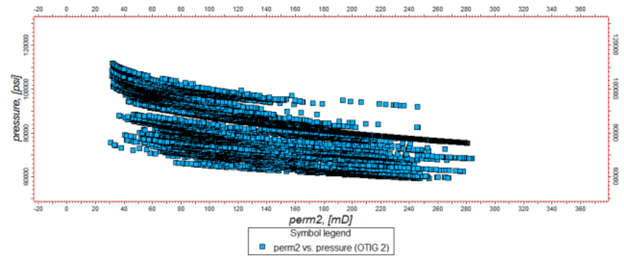

Figure 19: Display of Pressure - Permeability Relationship for OTIG 2.

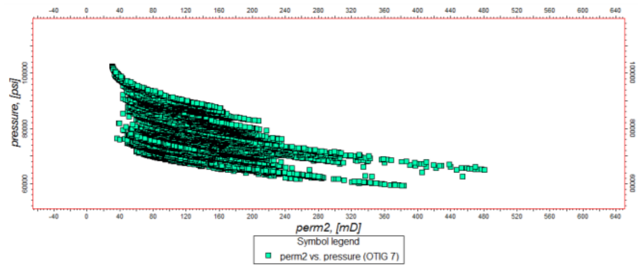

Figure 20: Display of Pressure- Permeability Relationship for OTIG 7.

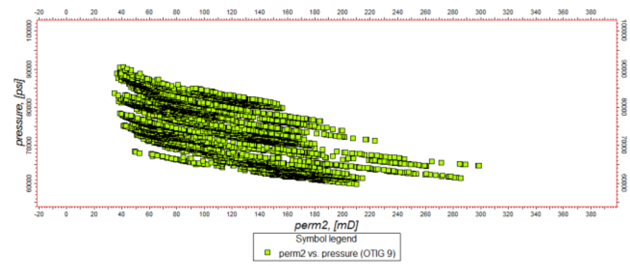

Figure 21: Display of Pressure- Permeability Relationship for OTIG 9.

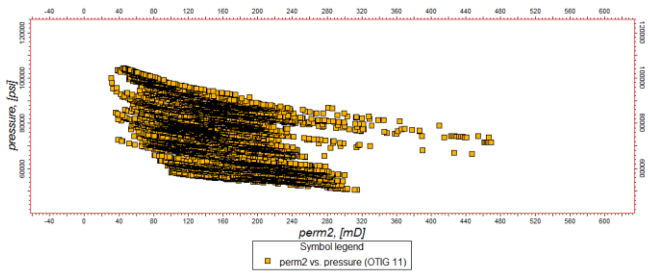

Figure 22: Display of Pressure- Permeability Relationship for OTIG 11.

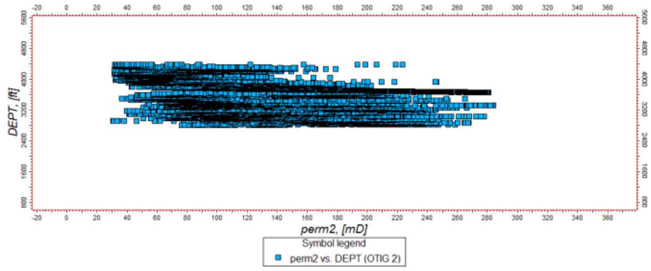

Figure 23: Display of Depth- Permeability Relationship for OTIG 2.

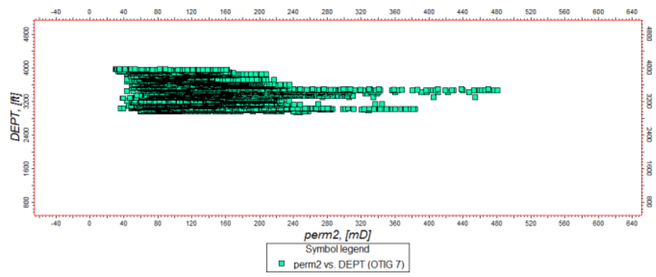

Figure 24: Display of Depth- Permeability Relationship for OTIG 7.

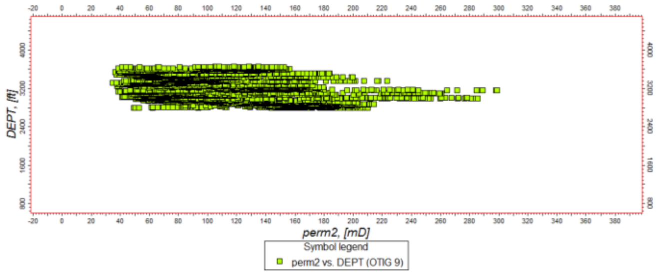

Figure 25: Display of Depth - Permeability Relationship for OTIG 9.

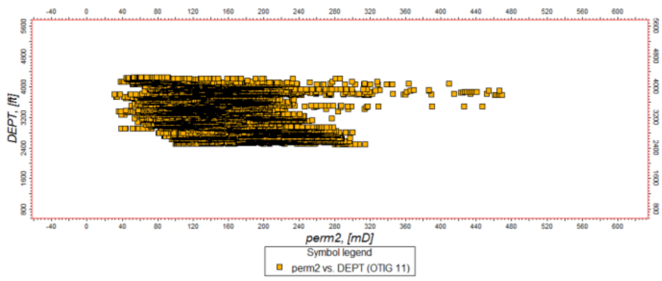

Figure 26: Display of Depth- Permeability Relationship for OTIG 11.

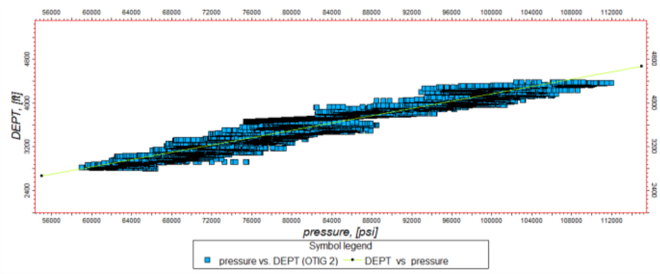

Figure 27: Display of Depth - Pressure Relationship for OTIG 2.

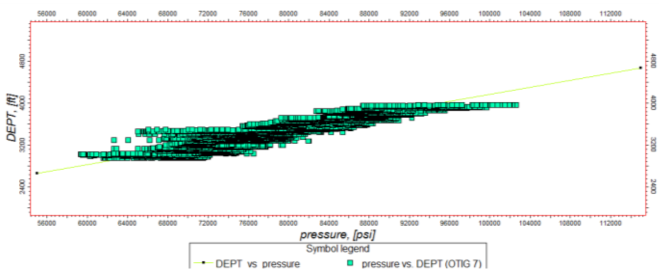

Figure 28: Display of Depth - Pressure Relationship for OTIG 7.

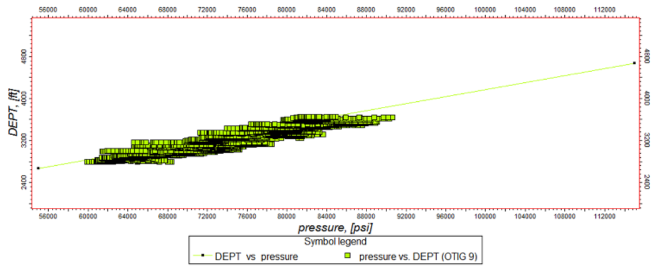

Figure 29: Display of Depth - Pressure Relationship for OTIG 9.

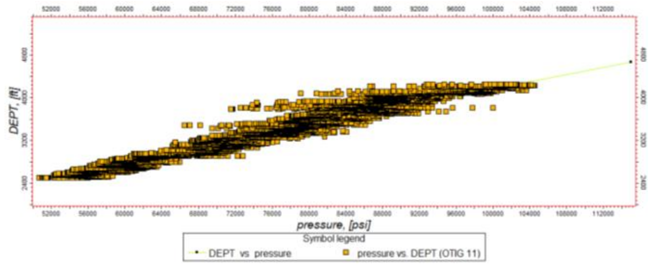

Figure 30: Display of Depth- Pressure Relationship for OTIG 11.

5. Discussion

5.1 Introduction

The results presented in chapter four are discussed in this chapter. Table 5 shows the different well log data used in the wells (OTIG 2, OTIG 7, OTIG9 and OTIG 11), all have density, neutron, sonic, gamma and SP logs. These logs are effectively used to achieve the aim and objectives of this research.

5.2 Porosity

Porosity is an essential parameter in the search for groundwater or hydrocarbon exploration. Oil and gas explorers and producers are also interested in the porosity of a potential hydrocarbon reservoir rock. The range of porosity value for the well are as follows: OTIG 2: 0.011(1.1%) to 0.280 (28.0%), OTIG 7: 0.001(0.1%) to 0.268 (26.8%), OTIG 9: 0.040 (4.0%) to 0.309(30.9%) and OTIG 11 is from 0.021 (2.1%) to 0.278 (27.8%). According to Levorsen (1964), rocks have negligible porosity when ≤ 5%, poor porosity when >5 ≥ 10%, good porosity when > 10 ≤ 20%, very good when > 20 ≤ 30% and excellent when >30%. Based on this classification, the porosity values recorded for OTIG 9 is classified as excellent and very good for OTIG 2, OTIG 7 and OTIG 11.

5.3 Permeability

Permeability is the most important physical property of a porous medium. It measures quantitatively the ability of a porous medium to transmit fluid. Permeability of rocks depend largely on the interconnectivity of the pore spaces, the grain size of rocks and cementation between the rock grains. A rock could be extremely porous, but if the pores are not interconnected, the rock would be impermeable. The results of well permeability ranges from 34.999mD to 228.127mD for OTIG 2, 65.761mD to 306.360mD for OTIG 7, 68.680mD to 278.089mD for OTIG 9, and from 61.039mD to 207.913mD for OTIG 11. Both Levorsen (1967) and Rider (1996) classified reservoir quality based on permeability values as follow; ≤10mD (poor to fair), > 10 ≤ 50mD (moderate), > 50 ≤ 250mD (good), > 250 ≤ 100mD (very good), and >1000mD (excellent). Based on this classification, wells OTIG 2 and OTIG 11 are classified as good whereas well OTIG 7 and OTIG 9 are very good.

5.4 Overburden or Geostatic Pressure

As deposition and accumulation of sediments increases to a greater thickness, overburden stress (vertical stress) is induced by the weight of the overlying formations or rocks. Overburden or geostatic pressure is the pressure on rock from the weight of rock and earth above the formation, thus porosity and permeability are reduced (Knut, 2010). When overburden pressure is low, it implies the formation is loosely packed, and there is a lot of space for sand grains to realign under pressure. The results of the pressure values of the wells range from 66813.328psi to 109928.054psi for OTIG 2, 67633.593psi to 90298.351psi for OTIG 7, 61926.863psi to 84783.570psi for OTIG 9 and from 68870.750psi to102445.796psi for OTIG 11.

5.5 Porosity – Permeability Correlation

Figure 7 – 10 Show the relationship between porosity and permeability for the four wells. It is observed that there is an exponential increase in porosity and permeability values in all the wells.

5.6 Porosity – Pressure Correlation

It is observed from figure 11 – 14 which shows the Porosity and overburden pressure relationship that Porosity decreases with increase in overburden pressure. The deeper the formation, the more pressure from overburden which causes compaction of the formation and reduction in porosity.

5.7 Porosity – Depth Correlation

Figure 15 – 18 show depth – Porosity relationship for the wells. There is a normal porosity decrease as depth increases due to the effect of compaction resulting from weight of overlying rocks. However, Porosity inversion was observed at some point in the well as depth increases, this can be attributed to under-compaction of overlying rocks.

5.8 Permeability – Pressure Correlation

Figure 19 – 22 show overburden pressure and permeability relationship for the four wells. There is a general decrease in permeability as overburden pressure increases, this implies that the higher the overburden pressure, the lower the permeability because higher pressure causes reduction in porosity and thus reduction in permeability.

5.9 Permeability – Depth Correlation

There is an exponential decrease in permeability as depth increases due to increase in overburden pressure resulting from increase in compaction as shown from figure 23 – 26.

5.10 Pressure – Depth Correlation

Figures 27 to 30 show that there is linearity in the relationship between depth and overburden pressure, as overburden pressure increases with depth. This is ideal since the deeper the depth of burial, the higher the confining overburden pressure and this shows that the formation is well compacted.

5.11 Delineation of Reservoir

The top and base of the identified reservoirs of interest for wells OTIG2, OTIG7, OTIG9 and OTIG11 are shown in figure 4 to 6. The litho-stratigraphic correlation revealed that each reservoir sand unit spread across the wells and differs in thickness with some unit occurring at greater depth than their corresponding unit. This could possibly be as a result of subsidence and/or faulting.

6. Conclusion

From the result of this study, the following conclusions are reached.

i. There is an exponential increase in porosity and permeability values in the wells.
ii. Porosity decreases with increase in overburden pressure.
iii. Porosity decreases as depth increases due to the effect of compaction resulting from weight of overlying rocks.
iv. There is a general decrease in permeability as overburden pressure and depth increases.
v. There is linearity in the relationship between depth and overburden pressure.
vi. The reservoir of wells OTIG 9 and OTIG 11 are more potential and productive compared to OTIG 2 and OTIG 7.

Recommendation

In the event of this study, some challenges were encountered in well data handling and management, thus the following recommendations were made: 3-D seismic and vertical seismic profiling (VSP) data should be incorporated into related work to allow for detailed and complimentary study of oil wells. As this will give room or make provision for the generation and analysis of seismic images or sections that will reveal more details of the geologic features of the well.

Acknowledgement

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