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Petrophysical And Geostatistical Modelling Of Rex Field, Coastal Swamp, Niger Delta

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Abstract: Petrophysical properties such as porosity, water saturation Net to Gross (NTG) and hydrocarbon volumes were estimated and integrated to identify potential hydrocarbon reservoirs, assess reservoir quality and productivity, and estimate hydrocarbon volumes to reduce exploration and development risks. Rex field is located the Niger Delta which is reputed as one of the most prolific petroleum provinces of the world, found in the Gulf of Guinea on the West Coast of Central Africa. It is located at latitudes $4^0$490 N and longitude $6^0$00 E, The REX Field is located in the coastal swamp at a water depth of twenty-five meters and it is part of a block area a little above 800km² areas in the southeastern Niger Delta. Wells in the Rex Field consist of basic data needed to compute the petrophysical properties that was required for geomodelling except for REX-05 that came with a missing gamma ray log. Composite volume of shale was therefore estimated from other vshale indicators in REX-05. Probabilistic assessment of the reservoirs was done using a probabilistic assessment tool of porosity, permeability net to gross (NTG) and a variogram model was developed. Reservoir petrophysical properties of the REX Field was determined from well log data from six identified reservoirs, the calculated porosity ranged between 0.22-0.32, water saturation was estimated from resistivity logs showing variation between 0.25 and 0.49. Other petrophysical parameters, such as Net to Gross (NTG) for A04, B04, C01 ranges between 0.744-0.99 and net pay between 21- 120. Geostatistical models showed a laterally flattened continuity, with sand-silt facies tested across various reservoirs. The identified oil reservoirs have stock tank oil initially in place (STOIIP) of 190mbo and the gas reservoir with NTG 0.27-0.99 and net pay range between 21- 130 with a Gas initially in place(GIIP) OF 110bcf. It is therefore recommended that the gas potential of the field be exploited with more concentration on improvement of field development methods

Keywords: Petrophysical Properties, Niger Delta, Reservoir Characterization, Hydrocarbon Volumes.

1.0. INTRODUCTION.

Petrophysical properties such as porosity, water saturation and NTG and hydrocarbon volumes were estimated and integrated to identify potential hydrocarbon reservoirs, assess reservoir quality and productivity, estimate hydrocarbon volumes, reduce exploration and development risks. Gamma-ray log was used to delineate the lithologies at the pre-determined depth intervals. The American Petroleum Institute (API) values ranges from sandstone line 0 to shale line 125. As the signature of the log moves towards the higher values, the formation becomes shalier. The delineation approach enabled us to estimate and establish the lithological sequence of the formation of the study area. To determine the ratio of sand to shale of the subsurface geology of the study area, Gamma ray log delineated into sections with two litho faces, namely, sandstones and shale. The gamma ray log reflects the shale content of sedimentary formations. Clean sandstones and carbonates normally exhibit a low level of natural radioactivity, while clay minerals and fluid particles in shales show higher levels of radioactivity due to adsorption of the heavy radioactive elements. To calculate the porosity, I use the rock matrix density, the fluid density, and the bulk density. The fluid density depends on whether the well encountered water or hydrocarbons which was determined by the electrical resistivity log. This was based on the fact that, sonic transit time is directly related to the acoustic velocity which is a function of formation lithology and porosity. The sonic log is simply a recording of the time required for a sound wave to traverse one foot of formation known as interval transit time. Sonic log is also a measure of a formation capacity to transmit sound waves. Geologically, this capacity varies with lithologies and rock texture, notably porosity, when the lithology is known. This makes the sonic log very useful as a porosity log. Integrated sonic transit times are also useful in interpreting seismic records. A sudden increase in transit time with depth indicates the presence of abnormal pressure. The sonic transit time values were obtained using the simple ratio method. The Sonic log velocities were crossed-checked with the correlative two-way-travel (TWT) seismic velocity (checkshots) data. Geostatistical methods provide tools for better inference from limited data in constructing a 3D reservoir model. These include incorporation of depositional interpretation using propensity analysis, variogram analysis, and the hierarchical modelling framework according to Rao et.al.,(2014), they also noted that propensity analysis can help the transition from qualitative description to quantitative analysis, bridge the gap between the descriptive geology and quantitative modelling, and provides useful constraints to condition the facies model to be geologically realistic. Variogram analysis can help characterize the continuity of rock properties, including geological object size and anisotropy, therefore it should be noted that geostatistical models of discrete lithofacies variables are important because of their use in constraining porosity and permeability models. Geostatistical methods for modelling porosity include kriging, sequential indicator simulation (SIS) and sequential Gaussian simulation (SGS). According to Rao et.al, (2014) Kriging generally produces smoother results, as the variance of the kriging model is commonly smaller than the variance of the data used in the kriging. SGS can be considered to be a two-step modelling workflow that performs a stochastic simulation based on kriging results. Sometimes, co-kriging or co-simulation can be used when more densely sampled seismic data is available and can be calibrated with porosity. The lithofacies model is often used to constrain the spatial distribution of porosity using SGS, because in the hierarchy of subsurface heterogeneities, depositional facies govern spatial and frequency characteristics of porosity to a large extent. Even though porosity can still be quite variable within each facies, the porosity statistics by facies generally exhibit less variation (Ma *et al.*, 2008).

1.2. LOCATION OF REX FIELD

The study area is located the Niger Delta which is reputed as one of the most prolific petroleum province in the world, found in the Gulf of Guinea on the West Coast of Central Africa. It is located at latitudes $4^0$490 N and longitude $6^0$00 E at the southern part of Nigeria (Doust, and Omatsola,1990) It is bounded in the south by the Gulf of Guinea and in the North by older (Cretaceous) tectonic elements which include the Anambra Basin, Abakaliki uplift and the Afikpo syncline. In the east and west respectively, the Cameroon volcanic line and the Dahomey Basin mark the bounds of the Delta, Figure. 1. The fields form part of the Coastal Swamp Depobelt which is bounded from the North and Central swamp Depobelt by a regional fault which is trending in North West and South Eastern direction and to the southern part a counter-regional fault separating it from the Offshore Depobelt (Figure 2). Rex Field is an extensional fault compartments located in the North-Eastern part Eastern Niger Delta (Figure 3). Rex Field lies between a major northwest-southeast trending structure-building fault and an antithetic fault extending Southwest-Northeast. The REX Field is located in the swamp at a water depth of twenty-five meters and it is part of a block area a little above 800km² and is located in the swamp to shallow water offshore areas in the southeastern Niger Delta.

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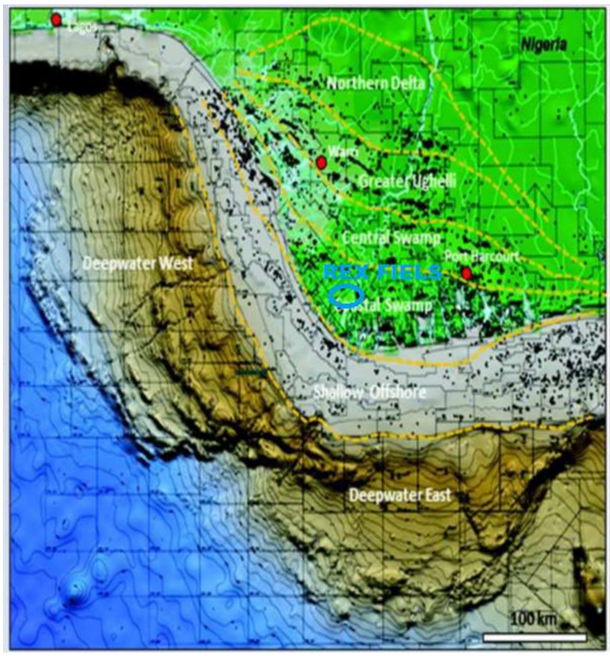

Figure 1. Schematic diagram showing Niger Delta Depobelts (after Okpogo et al., 2018)

1.3. WELL LOG AND PETROPHYSICAL ANALYSIS FOR REX FIELD

All wells consist of basic data needed to compute the petrophysical properties that were to be required by the geomodeler and other team members except for REX-05 that came with a missing gamma ray log. Composite volume of shale was therefore estimated from other vshale indicators in REX-05. Confirmatory data such as overburden corrected porosity and dean stark water saturation could have improved the confidence level of the analysis if it were to be available. Due to the unavailability of confirmatory data, the properties were painstakingly generated within a very careful formation evaluation procedure. The basic analysis procedure we used involves the following steps, each of which is described in the following sections: Collect data from either providers field tapes or high accuracy digitization of paper log prints; Merge log runs and depth shift curves between logging passes, by correlation and selection of reservoirs; Apply environmental corrections and normalize porosity and gamma-ray logs; Compute shale volume from the gamma ray; Compute total porosity and shale-corrected (‘‘effective’’) porosity from the density, neutron, and sonic logs.

3.1. Determination of porosity.

Total porosity’’ is the total pore volume of the rock and includes porosity filled with hydrocarbons, moveable water, capillary-bound water, and clay-bound water (Hook, 2003). Both the density and neutron logs are considered total porosity tools, because they detect all the porosity in a region surrounding the logging tool, although they have different volumes of investigation and are responding to different physical phenomena that are indirectly related to porosity (electron density in the case of the bulk-density log and hydrogen density in the case of the neutron log). In shaley formations, they read very different values; in particular, the neutron log is strongly affected by hydrogen associated with clay-bound water and reads a much higher apparent porosity than the density log. ‘‘

was determined from the formula

$$\acute{Ø}_{density} = \frac{p_{ma} - p_{b}}{P_{ma} - p_{f}} \text{--} (1)$$

Where ᴘma = matrix (or grain) density, pf = fluid density and pb = bulk density (as measured.

Porosities calculated from density log using values from the range 0.45- 0.55g/cc and 0.85-0.95g/cc match point-to-point with the porosity calculated from Gaymard's approximation in gas and oil zones respectively.

3.2. Determination of Sonic Velocity

Sonic transit time is directly related to the acoustic velocity which is a function of formation lithology and porosity. A sudden rise in transit time with depth shows the presence of abnormal pressure. The Sonic log velocities were crossed-checked with the correlative two-way-travel (TWT) seismic velocity (checkshots) data. Poisson's ratio, σ, is defined in the relation as:

$V_p = \frac{1}{\Delta t}(Ft\ \{\text{us}\} - 1)$ ------------------------ (2)

3.3. Determination of Permeability (K) Reservoir management strategies are as realistic as the "image" of spatial distribution of rock properties. Permeability is the most difficult property to determine and predict. Many investigators have attempted to capture the complexity of permeability function in models with general applicability. While these studies contribute to a better understanding of the factors controlling permeability, they demonstrate that it is an illusion that a "universal" relation between permeability and variables from wireline logs can be found. Empirical models are based on the correlation between permeability, porosity, and irreducible water saturation. **T**he four empirical models used the most: Tixier, Timur, Coates & Dumanoir, and Coates.

3.4. Determination of Water Saturation, Sw

To estimate water saturation Sw of un-invaded zone, the method used requires a water resistivity Rw value at formation temperature considered from the porosity and resistivity logs within clean water zone, using the inverse Archie method. Fundamental equation in petrophysics that relates water saturation (Sw) to resistivity (Rt), water resistivity (Rw), porosity (φ), and empirical parameters (a, m, n):

Sw = (a * Rw / Rt)^(1/n) * (1 / φ^m) (Simplified form-----------------------(3)

Where: Sw: Water saturation (fraction) ,Rt: True formation resistivity (ohm-m) ,Rw: Water resistivity (ohm-m) ,φ: Porosity (fraction) and a, m, n: Empirical parameters (formation factor and saturation exponent). The presence of shale (clay) in a rock can significantly affect its resistivity and must be accounted for, often using a shale volume correction.

3.5Volume of shale calculation

Shale volume (Vsh) is commonly estimated from well logs using techniques like Gamma Ray (GR) logs, neutron-density crossplot, and sonic logs. These methods leverage the distinct responses of shale and other reservoir rocks to various logging measurements to quantify the shale content within a formation. Gamma Ray (GR) is the most used log in estimating volume of shale. Shales typically have higher natural radioactivity than other reservoir rocks like sandstones or carbonates. This higher radioactivity is recorded by the GR log, with higher GR values indicating higher shale content. he simplest approach involves a linear relationship between GR readings and shale volume (Vsh). More sophisticated methods may use non-linear corrections or incorporate other log data to improve accuracy. A common linear formula is:

Vsh = (GR - GRcl) / (GRsh - GRcl) ---------- (11),

Where GR is the measured gamma ray value, GRcl is the value for clean (shale-free) zones, and GRsh is the value for 100% shale.

3.6. Geostatistical modelling

The facies logs determined from the wells were upscaled into the zone model. The facies proportions for each well were generated per reservoir level and used to build the conceptual framework. Variogram analysis was run to extract the geological trends that are present in the data Facies was run for all the compartments. Figure 9 shows the facies model histogram for the six reservoirs as a means of QC of the final distribution results. The raw porosity logs were quality checked and upscaled (with bias to facies) into the

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structural grid using arithmetic averaging. Data analysis was done to fit appropriate distribution curves to the upscaled porosity logs for each. The modelled vertical variogram and conceptual area variogram was used to populate the porosity (conditioned to Facies) using the sequential Gaussian simulation algorithm in the model. Figure 10 shows the porosity model histograms for the six reservoir.

4.0. RESULTS AND DISCUSION

4.1. WELL CORRELATION AND WELL TOP SELLECTION.

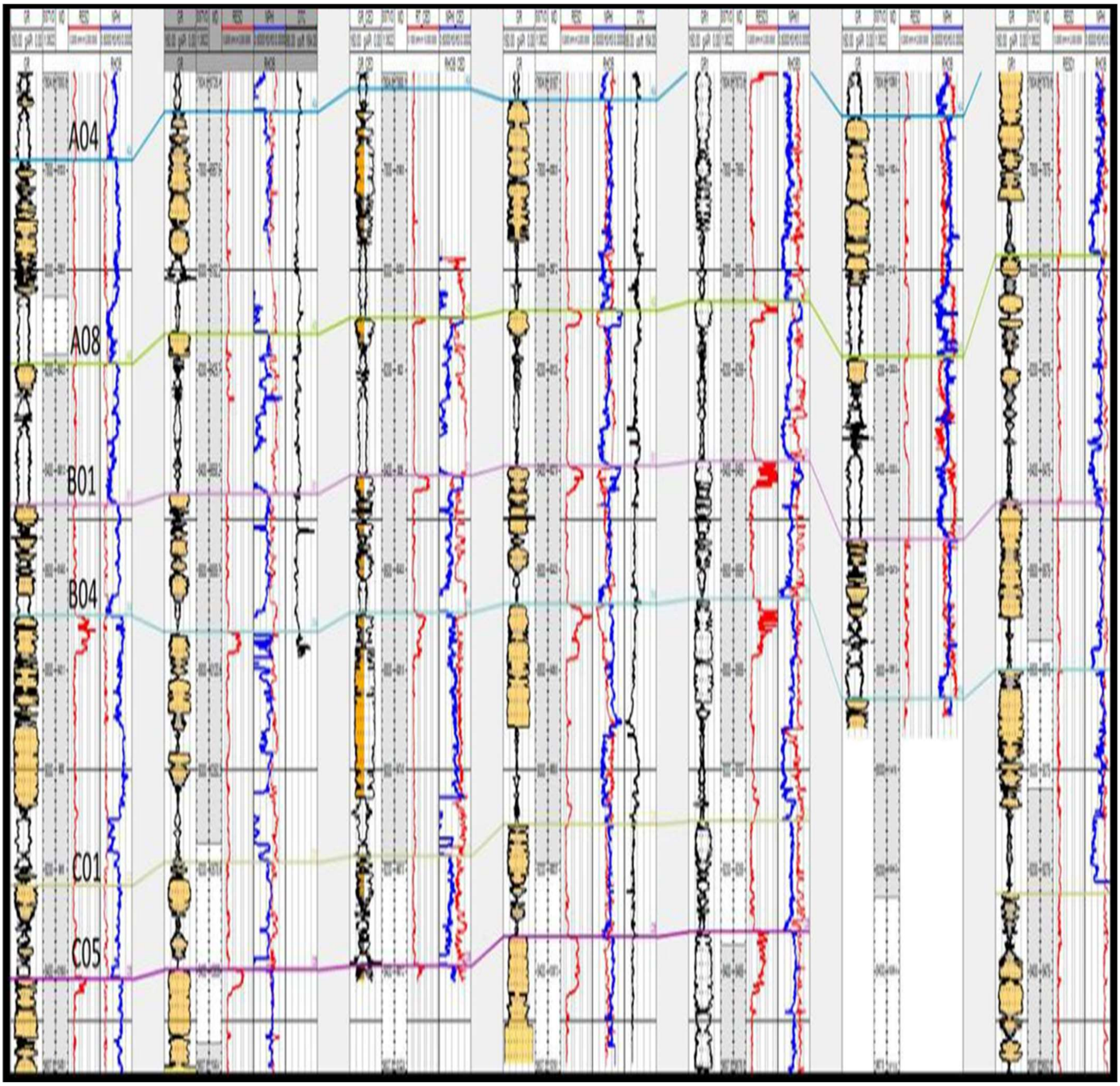

Figure 2:

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Table 1: Reservoir Top and Base identification (A04, A08 and B01)

Wells	A04				A08				B01			
	Top		Base		Top		Base		Top		Base	
	(MD)	Tvdss	(MD)	Tvdss	(MD)	Tvdss	(MD)	Tvdss	MD	Tvdss	MD	Tvdss
REX-01	7662	7593	7990	7921	9391	9322	9794	9725	9391	9322	9794	9725
REX-04	8227	7659	8561	7966	10024	9331	10215	9510	10024	9331	10215	9510
REX-05	8049	7689	8369	7989	9890	-9416	10047	9563	9890	-9416	10047	9563
REX-05c	8049	7662	8369	7962	9890	9390	10047	9568	9890	9390	10047	9568
REX-06	8818	7758	9170	8057	10804	9475	10909	9530	10804	9475	10909	9530
REX-06c	8818	7684	9170	7983	10804	9401	10950	9856	10804	9401	10950	9856
REX-7P	8105	7779	8460	8057	10187	9413	10760	10199	10187	9413	10760	10199
REX-9P	1146	11365	12218	12123	10827	10732	10965	10870	10827	10732	10965	10870

Table 2: Reservoir Top and Base identification (B04, C01 and C05)

Wells	B04				C01				C05			
	Top		Base		Top		Base		Top		Base	
	(MD)	Tvdss	(MD)	Tvdss	MD	Tvdss	MD	Tvdss	MD	Tvdss	MD	Tvdss
REX-01	7662	7593	7990	7921	9391	9322	9794	9725	9391	9322	9794	9725
REX-04	8227	7659	8561	7966	10024	9331	10215	9510	10024	9331	10215	9510
REX-05	8049	7689	8369	7989	9890	-9416	10047	9563	9890	-9416	10047	9563
REX-05c	8049	7662	8369	7962	9890	9390	10047	9568	9890	9390	10047	9568
REX-06	8818	7758	9170	8057	10804	9475	10909	9530	10804	9475	10909	9530
REX-06c	8818	7684	9170	7983	10804	9401	10950	9856	10804	9401	10950	9856
REX-7P	8105	7779	8460	8057	10187	9413	10760	10199	10187	9413	10760	10199
REX-9P	1146	11365	12218	12123	10827	10732	10965	10870	10827	10732	10965	10870

Table 3: Extracted fluid contacts of reservoirs from various well logs

REX_A04Reservoir				**REX_A08Reservoir**				**REX_BO1 Reservoir**			
Wells	Fluid Type	Fluid cont.	Contact depth	**Wells**	Fluid Type	Fluid cont.	Contact depth	**Wells**	Fluid Type	Fluid cont.	Contact depth
REX-01	Oil	OWC	7625	REX-01	Gas	GWC	8106	REX-01	Gas	GWC	8440
REX-04	Oil	Wet		REX-04	Gas	GWC	8111	REX-04	Gas	GWC	8448
REX-05	Oil	Wet		REX-05	Gas	GWC	8135	REX-05	Gas	GWC	8470
REX-05c	Oil	Wet		REX-05c	Gas	GWC	8109	REX-05c	Gas	GWC	8444
REX-06	Oil	Wet		REX-7P	Wet	----	----	REX-7P	Wet	-----	-----
REX-06c	Oil	Wet		REX-9P	Wet	----	----	REX-9P	Wet	-----	-----
REX-7P	Oil	Wet									
REX-	Oil	Wet									

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8H											
	REX_B04Reservoir				**REX_C01 Reservoir**				**REX_C05 Reservoir**		
Wells	Fluid Type	Fluid cont.	Contact depth	**Wells**	Fluid Type	Fluid cont.	Contact depth	**Wells**	Fluid Type	Fluid cont.	Contact depth
REX-01	Oil	OWC	8774	REX-01	Oil	OWC	9105	REX-01	Oil	OWC	9446
REX-04	Oil	OWC	8782	REX-04	Oil	OWC	9108	REX-04	Oil	OWC	9445
REX-05	Oil	OWC	8801	REX-7P	----	----	-----	REX-05	Oil	OWC	9474
REX-05c	Oil	OWC	8774	REX-8H	----	----	-----	REX-05c	Oil	OWC	9448
REX-06	Oil	OWC	8846					REX-06	Oil	OWC	9525
REX-06c	Oil	OWC	8772					REX-06c	Oil	OWC	9452
REX-7P	Oil	OWC	8768					REX-7P	Oil	OWC	9445
REX-8H	Wet	-----	-----					REX-8H	Oil	---	----
REX-9P	Wet	-----	-----					REX-9H	Oil	---	-----

Table 4: Pay analysis Result for Reservoir A08

Wells	Reference				Sand				Pay						
	Top		Base		Gross	Net	NTG	por	Net pay	NTG pay	Por	SW	Fluid type	Fluid contact	
	Md	Tvdss	MD	Tvdss											
REX-01	8129	8060	8299	8230	170	154	0.90	0.28	44	0.26	0.29	0.16	Gas	GWC	8106
REX-04	8681	8077	8858	8242	164	140	0.85	0.30	32	0.20	0.34	0.14	Gas	GWC	8111
REX-05	8513	8124	8684	8284	161	109	0.68	0.29	12	0.08	0.32	0.28	Gas	GWC	8135
REX-05c	8513	8097	8684	8258	161	109	0.68	0.29	12	0.08	0.32	0.28	Gas	GWC	8109
REX-7P	8630	8189	8818	8334	145	106	0.73	0.27	0	0	---	---	Wet	----	----
REX-9P	12553	12458	13053	12958	500	407	0.81	0.32	0	0	---	---	Wet	----	----

Table 5: Pay analysis Result for Reservoir A04

Wells	Reference				Sand				Pay						
	Top		Base		Gross	Net	NTG	Por	Net pay	NTG pay	Por	SW	Fluid type	Fluid contact	
	MD	Tvdss	MD	Tvdss											
REX-01	8725	8656	8984	8915	259	255	0.986	0.27	113	0.44	0.28	0.22	Oil	OWC	8774
REX-04	9315	8667	9580	8915	148	146	0.992	0.34	113	0.46	0.33	0.16	Oil	OWC	8782
REX-05	9139	8712	9534	9083	370	366	0.987	0.25	82	0.22	0.28	0.29	Oil	OWC	8801
REX-05c	9139	8686	9534	9057	371	366	0.990	0.25	82.2	0.22	0.28	0.29	Oil	OWC	8774
REX-06	10040	8807	10249	8922	190	176	0.929	0.32	38	0.20	0.36	0.16	Oil	OWC	8846
REX-06c	10040	8733	10249	8922	190	176	0.929	0.32	38	0.20	0.34	0.16	Oil	OWC	8772
REX-7P	9266	8692	9786	9097	405	380	0.937	0.24	72	0.18	0.27	0.22	Oil	OWC	8768
REX-8H	9866	8450	10230	8719	269	247	0.985	0.26	0	0	----	----	Wet	-----	-----
REX-9P	14111	14016	14242	14147	131	129	0.985	0.27	0	0	----	----	Wet	-----	-----

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Table 6: Pay analysis Result for Reservoir B01

Wells	Reference				Sand				Pay						
	Top		Base		Gross	Net	NTG	Por	Net pay	NTG pay	Por	SW	Fluid	Fluid contact	
	MD	Tvdss	MD	Tvdss											
REX-01	7662	7593	7990	7921	328	295	0.90	0.27	27.5	0.08	0.27	0.27	oil	OWC	7625
REX-04	8227	7659	8561	7966	307	279	0.91	0.29	0	0	-	-		Wet	---
REX-05	8049	7689	8369	7989	300	missing log								Wet	---
REX-05c	8049	7662	8369	7962	300	missing log								Wet	---
REX-06	8818	7758	9170	8057	299	291	0.97	0.33	0	0	---	---	---	Wet	----
REX-06c	8818	7684	9170	7983	299	291	0.97	0.33	0	0	---	---	---	Wet	
REX-7P	8105	7779	8460	8057	278	271	0.98	0.31	0	0	---	---	---	Wet	----
REX-9P	1146	11365	12218	12123	758	754	0.99	0.31	0	0	---	---	---	Wet	----

Table 7: Pay analysis Result for Reservoir B08

Wells	Reference				Sand				Pay						
	Top		Base		Gross	Net	NTG	Por	Net pay	NTG Pay	Por	SW	Fluid type	Fluid contact	
	MD	Tvdss	MD	Tvdss											
REX-01	8445	8376	8674	8605	229	203	0.90	0.28	59.5	0.26	0.29	0.18	Gas	GWC	8440
REX-04	9021	8393	9249	8606	212	203	0.96	0.31	51.7	0.24	0.31	0.21	Gas	GWC	8448
REX-05	8850	8440	9072	8649	208	189	0.91	0.31	30	0.14	0.30	0.11	Gas	GWC	8470
REX-05c	8850	8414	9072	8622	209	190	0.91	0.31	30	0.14	0.30	0.11	Gas	GWC	8444
REX-7P	8990	8471	9214	8651	180	168	0.94	0.28	0	0	----	----	Wet	-----	-----
REX-9P	13409	13314	13778	13683	369	353	0.99	0.28	0	0	----	----	Wet	-----	-----

Table 8: Pay analysis Result for Reservoir A04

Wells	Reference				Sand				Pay						
	Top		Base		Gross	Net	NTG	Por	Net pay	NTG pay	Por	SW	Fluid type	Fluid contact	
	MD	Tvdss	MD	Tvdss											
REX-01	9106	9037	9360	9291	254	189	0.744	0.26	21	0.083	0.20	0.47	Oil	OWC	9105
REX-04	9742	9067	9986	9295	228	200	0.875	0.28	23	0.101	0.24	0.51	Oil	OWC	9108
REX-7P	9870	9163	10157	9389	226	183	0.807	0.26	0	---	----	----	----	----	-----
REX-8H	10523	8845	11113	9212	367	326	0.887	0.25	0	----	----	----	----	----	-----

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4.2: VOLUME OF SHALE CUT-OFFS FOR FACIES CLASSIFICATION

Table 9: showing sand-shale facies classification.

Well /Vsh Cut-off	Sand	Silt	Shale
REX-01, REX-03, REX-05,	<35	35-50	>50
REX-07P, REX-09H			
REX-02	<27	27-45	>45
REX-04, REX-06	<20	20-30	>30
REX-07H	<20	20-25	>25
REX-09P, REX-08H	<20	20-40	>40

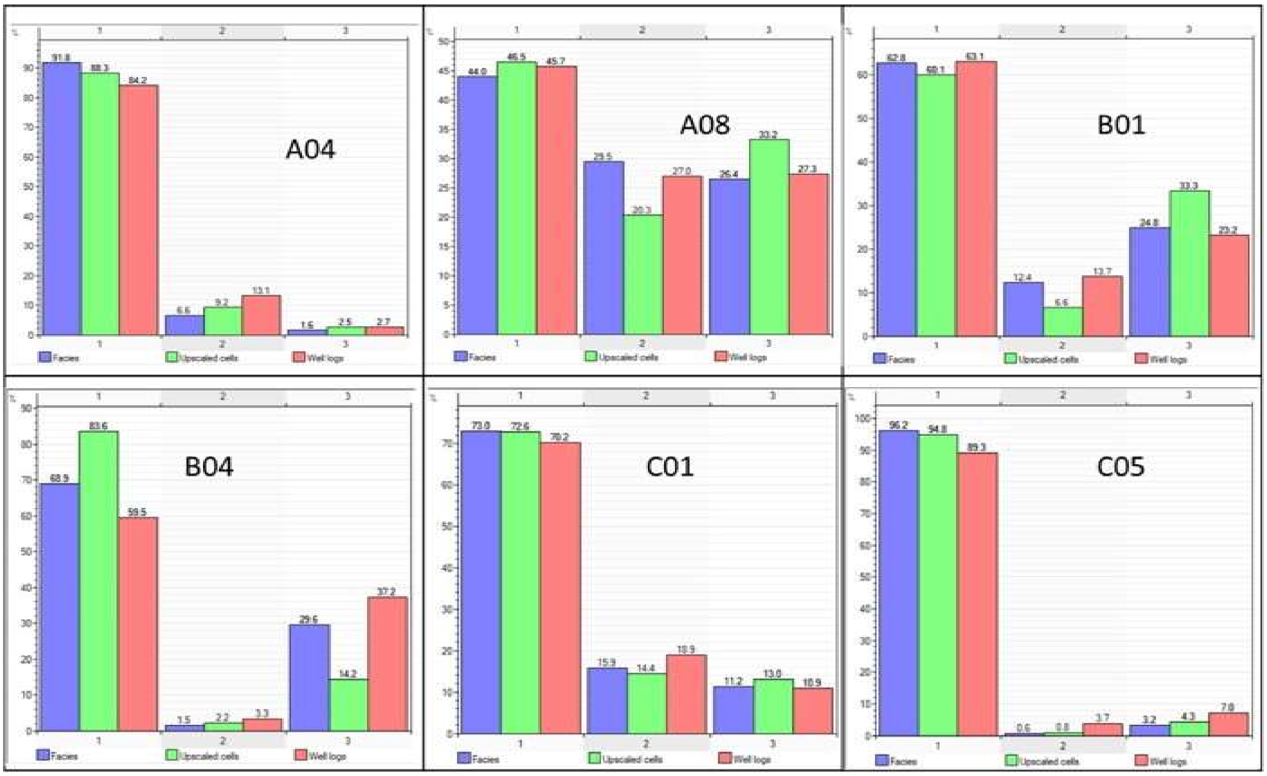

Figure 3: Facies Model Histograms for the A04, A08, B01, B04, C01 and C05 Reservoirs

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4.3: PETROPHYSICAL MODELLING

A. FLUID CONTACTS AND WATER SATURATION MODELLING

Table 10: Fluid contacts for REX Reservoirs

Contact	A04	A08	B01	B04	C01	C05
GWC (ftss)		8115	8448			
OWC (ftss)	7623			8773	9108	9445

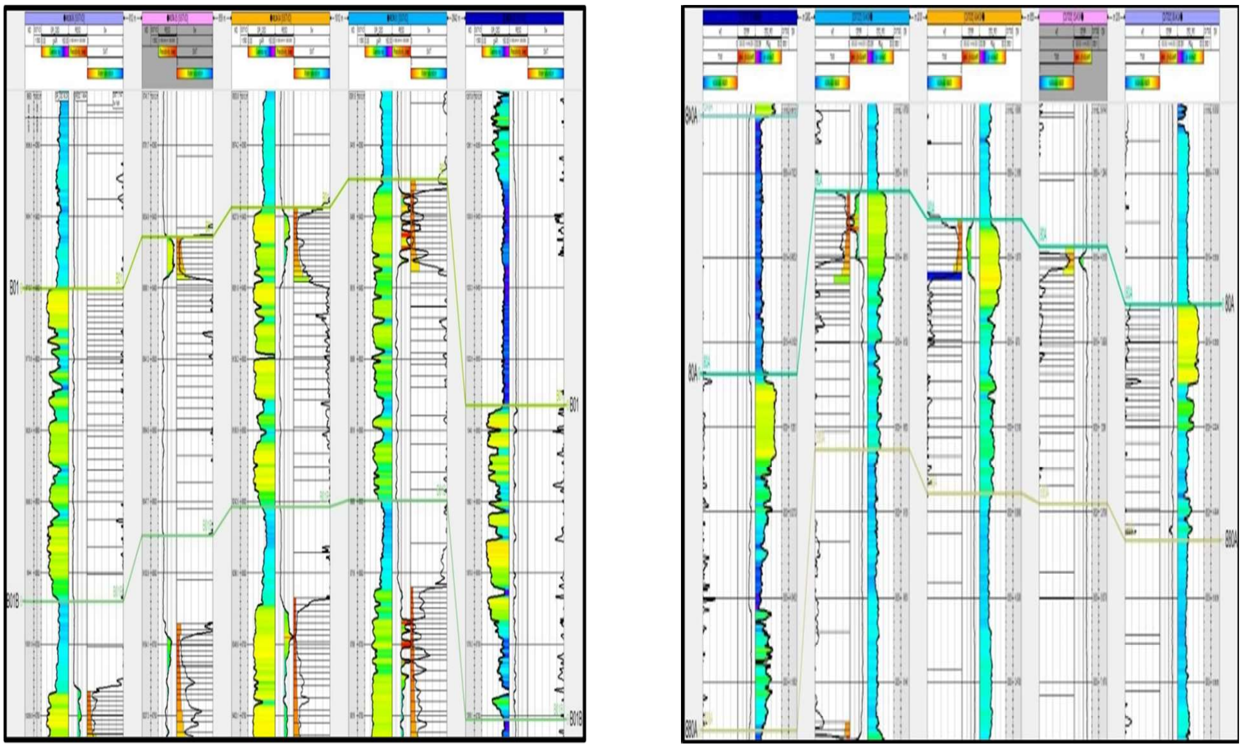

Figure 4 &5:A08 and B01 Reservoir Water Saturation Match

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B. POROSITY MODELLING

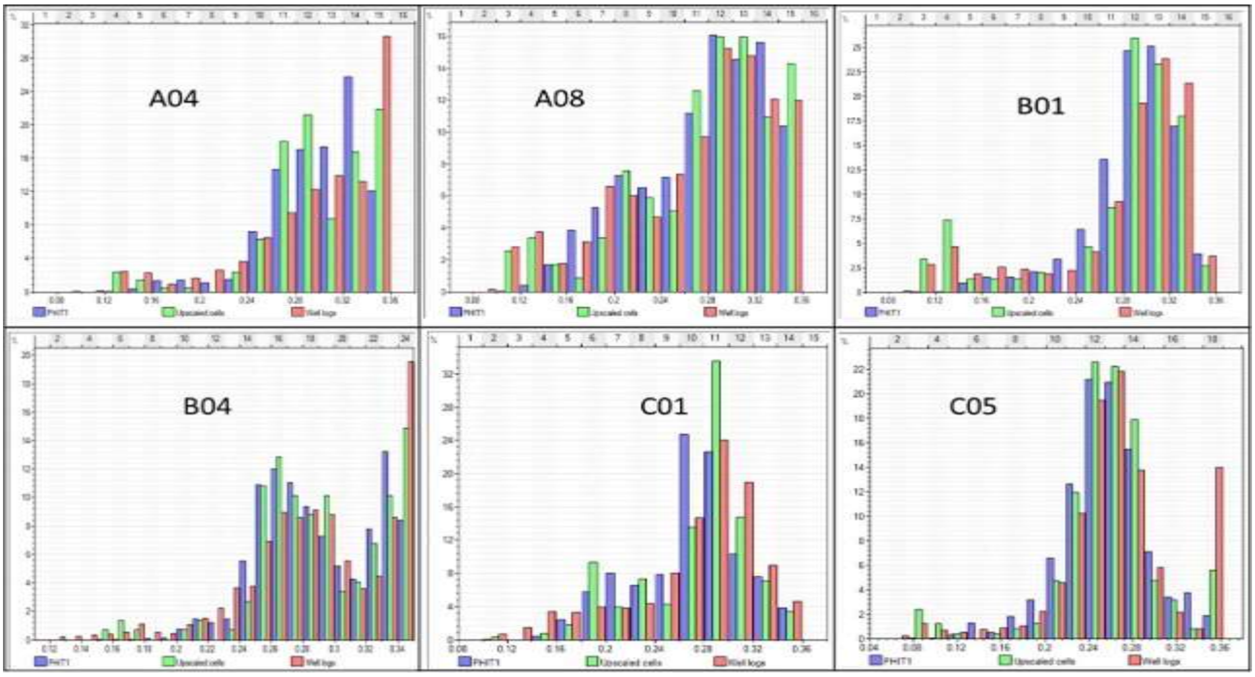

Figure 6: Porosity Model Histograms for the A04, A08, B01, B04, C01 and C05 Reservoirs

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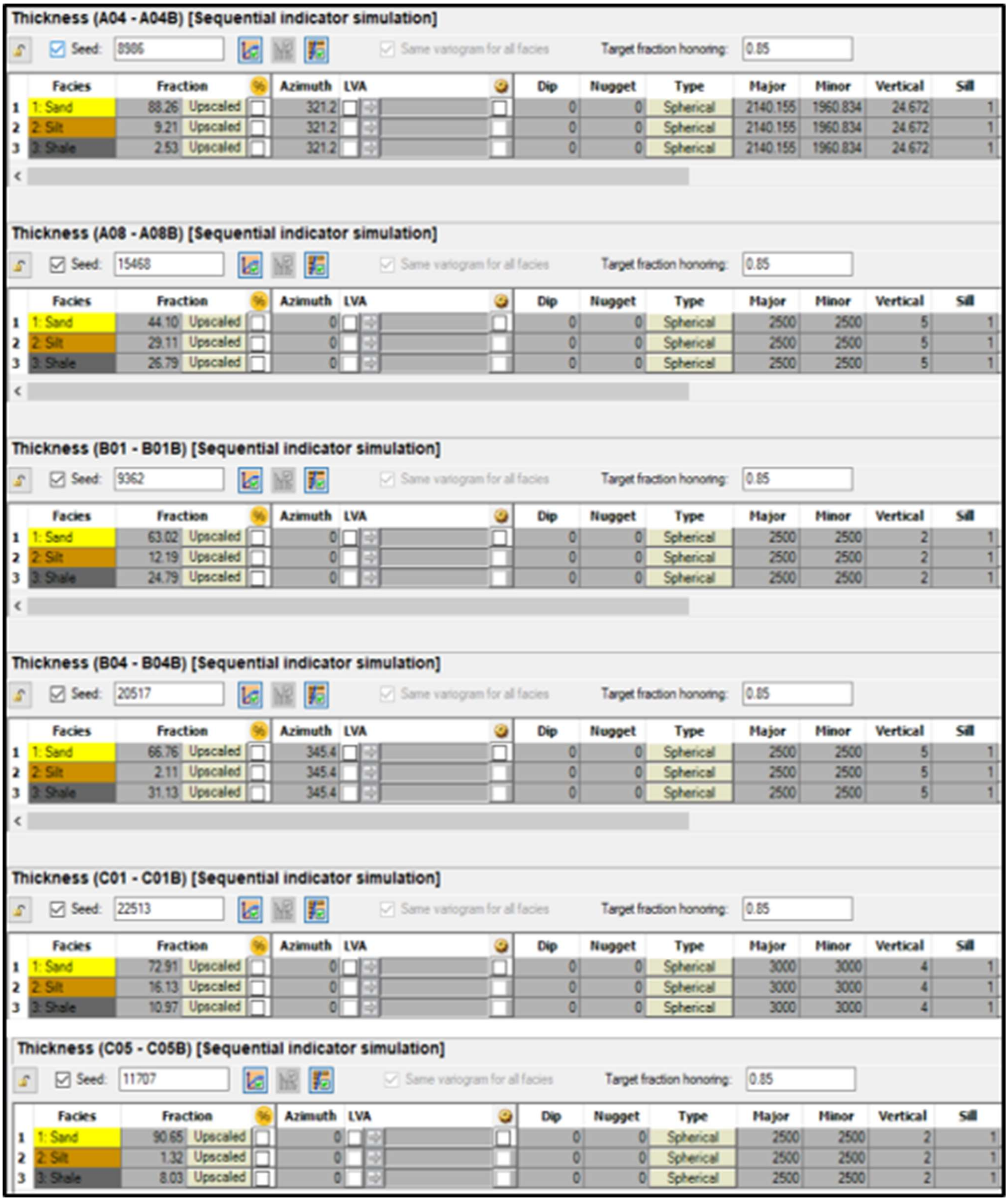
D. VAIROGRAM MODELLING



Thickness (A04 - A04B) [Sequential indicator simulation]

Seed: 8986 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	88.26	Upscaled	321.2		0	0	Spherical	2140.155	1960.834	24.672	1
2	2: Silt	9.21	Upscaled	321.2		0	0	Spherical	2140.155	1960.834	24.672	1
3	3: Shale	2.53	Upscaled	321.2		0	0	Spherical	2140.155	1960.834	24.672	1

Thickness (A08 - A08B) [Sequential indicator simulation]

Seed: 15468 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	44.10	Upscaled	0		0	0	Spherical	2500	2500	5	1
2	2: Silt	29.11	Upscaled	0		0	0	Spherical	2500	2500	5	1
3	3: Shale	26.79	Upscaled	0		0	0	Spherical	2500	2500	5	1

Thickness (B01 - B01B) [Sequential indicator simulation]

Seed: 9362 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	63.02	Upscaled	0		0	0	Spherical	2500	2500	2	1
2	2: Silt	12.19	Upscaled	0		0	0	Spherical	2500	2500	2	1
3	3: Shale	24.79	Upscaled	0		0	0	Spherical	2500	2500	2	1

Thickness (B04 - B04B) [Sequential indicator simulation]

Seed: 20517 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	66.76	Upscaled	345.4		0	0	Spherical	2500	2500	5	1
2	2: Silt	2.11	Upscaled	345.4		0	0	Spherical	2500	2500	5	1
3	3: Shale	31.13	Upscaled	345.4		0	0	Spherical	2500	2500	5	1

Thickness (C01 - C01B) [Sequential indicator simulation]

Seed: 22513 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	72.91	Upscaled	0		0	0	Spherical	3000	3000	4	1
2	2: Silt	16.13	Upscaled	0		0	0	Spherical	3000	3000	4	1
3	3: Shale	10.97	Upscaled	0		0	0	Spherical	3000	3000	4	1

Thickness (C05 - C05B) [Sequential indicator simulation]

Seed: 11707 | Same variogram for all facies | Target fraction honoring: 0.85

	Facies	Fraction		Azimuth	LVA	Dip	Nugget	Type	Major	Minor	Vertical	Sill
1	1: Sand	90.65	Upscaled	0		0	0	Spherical	2500	2500	2	1
2	2: Silt	1.32	Upscaled	0		0	0	Spherical	2500	2500	2	1
3	3: Shale	8.03	Upscaled	0		0	0	Spherical	2500	2500	2	1

Figure 7: Variogram models for the A04, A08, B01, B04, C01 and C05 Reservoir.

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4.3: RESERVOIR VOLUMETRICS

Table11 & 12: Estimation of Hydrocarbon Initially in Place for AO4 and A08

Parameters	LS	ML	HS
GRV (Acft)	3632.18	3632.18	3632.18
NTG	0.9	0.97	0.99
Porosity	0.27	0.31	0.33
Oil Saturation	0.8	0.84	0.85
BO	1.603	1.603	1.603
K	7758	7758	7758
STOIIP	P10	P50	P90
	3.98	4.36	4.66

Parameters	LS	ML	HS
GRV (Acft)	6718	10647	18545
NTG	0.68	0.81	0.9
Porosity	0.27	0.3	0.32
Oil Saturation	0.72	0.84	0.86
BO	0.00466	0.0048	0.005
K	43560	43560	43560
GIIP	P10	P50	P90
GIIP (BCF)	14.9	19.9	25.9

Table 13&14: **Estimation of Hydrocarbon initially in place for BO1 and B04**

Parameters	LS	ML	HS
GRV (Acft)	29664	31096	39001
NTG	0.9	0.94	0.99
Porosity	0.28	0.28	0.31
Oil Saturation	0.79	0.82	0.89
BO	0.00466	0.0048	0.005
K	43560	43560	43560
GIIP	P10	P50	P90
GIIP (BCF)	66.2	70.9	77.22

Parameters	LS	ML	HS
GRV (Acft)	88563	97600	100698
NTG	0.929	0.985	0.992
Porosity	0.24	0.27	0.34
Oil Saturation	0.71	0.78	0.84
BO	1.603	1.603	1.603
K	7758	7758	7758
STOIIP	P10	P50	P90
	85.3	98	113

Table 15: Estimation of Hydrocarbon initially in place for C05.

Parameters	LS	ML	HS
GRV (Acft)	60158	66843	75411
NTG	0.8	0.96	1
Porosity	0.25	0.27	0.29
Oil Saturation	0.62	0.78	0.88
BO	1	1.2	1.4
K	7758	7758	7758
STOIIP	P10	P50	P90
	73.9	90.4	110

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4.4: DISCUSION

This work evaluated six identified reservoirs from the Rex Field in the coastal swamp Niger Delta. The field data which was obtained with permission from an indigenous oil company, included data from log and seismic sections used to interpret and create geological models and examine heterogeneous properties. The six reservoirs were petrophysically interpreted, and possible pay analysis carried out; the average values of net-to-gross, porosity and water saturation was summarized. Net to gross was calculated from facies identified petrophysical and from porosity cut-off values, with an average of 0.81-0.91, which implies that the studied reservoir had high pay (oil and gas) reservoirs. It should be of note that the parts of the reservoir was not considered in the calculation of the reservoir although, reservoir in the different wells was treated individually in a bit to create segmented scenes which was used in the compartalization analysis. The well log correlation which was carried out using petrel software (2018) was adopted and content were identified resources picked and Top/bases of the reservoir were synchronize for the furtherance of the work. All the measured depths (MD), true vertical depths (TVD), true vertical thickness (TVT) and subsea true vertical depth (SSTVD) were identified for the reservoirs. REX Petrophysical data of reservoirs was analysed using the methods specified in chapter three with a focus on the Net-to-Gross, porosity and water saturation, which are the three basic parameters whose heterogeneity will be tested in the compartalization and geostatistical modelling.

REX A04 showed an average reservoir NTG of 0.95, porosity of 0.27% and water saturation of 0.27, while other REX A08 showed (NTG=0.81, porosity=0.32, and Sw=0.19), REX B01(NTG=0.94, porosity=0.30, and Sw=0.19), REX B04 (NTG=0.97, porosity=0.30, Sw=0.17), REX C01(NTG=0.83, porosity=0.22, Sw=0.49). While C05(NTG=0.95, porosity=0.26 and 0.25), it should of note that in the calculation of the above average petrophysical result (as shown in table 4) commutation exponent(m), saturation exponent(n) and tortuosity factor (a) reported as 1.73, 2 and 1.13, respectively were considered from available petrophysical data. The average NTG obtained for each reservoir from wells in the REX Field showed its large impact on reservoir estimation and computation hence its very first estimation before other (porosity and saturation) and it's used in estimation of compartalization of the reservoir. Porosity of each reservoir was estimated from logs with facies in reservoir, it was identified as excellent and showed both, gas and oil in voids with predictable higher storage potential. The saturation was estimated from resistivity logs using the Archie table and showed average variation between 6.17 and 0.49, and this has been infused in the creation of reservoir models and compartalization of the reservoir. Reservoir petrophysical, pay analysis was carried out using the above estimated petrophysical properties (NTG, porosity and water saturation) as shown in section (4.32 Tables A-E).

The reservoir shows that A04 show fluid type oil with a net pay of 27.5 and an OWC of 7625ft while A04 reservoir was wet. In other wells and not significantly showing third contacts which should be considered. Reservoir A08 is a gas reservoir and was observed with an average net pay of 12 in the various well but was wet in well REX 7P and 9P) but showed a distant gas-water contact at depths 8106ft, 8111 ft, 8135 ft and 8109 feet for wells REX 01, REX 04, REX 05 AND REX 05C, respectively. Pay analysis of reservoir B01 was evaluated as a gas reservoir with a Net pay of 30-59.5) and an NTG pay of 0.14-0.26. All that is wet in Well REX 7P and REX 9P. The gas-water contacts was significantly seen at depth 8440, 8448, 8470 and 8444. Just in REX-01, REX-04, REX-05 and REX-05C, respectively. So the reservoir B01 is an established gas reservoir, while BO4 was evaluated for all the wells in the Rex field both the abandoned wells had a significant of oil with OWC estimated for various wells and a Net pay of average 32-113, NTG pay of 0.18-0.46 but was wet and this work was not able to estimate fluid type in well REX 8H and REX 9P. Pay analysis results for reservoir CO1 show that it was found in only four wells, REX 01, REX 04, REX 7P and REX 8H, but had proper Net pay of 21 and 23 in REX 01 and REX 04 with significant oil water contact and depths of 9105 and 9108 feet. Probabilistic assessment of the reservoirs was done using a probabilistic assessment tool. Different scenarios of the rock and fluid properties were integrated with different possible gross rock volumes (GRV) to come up with the P10, P50 and P90 of STOIIP and GIIP. The different gross rock volumes were made with assumptions of slightly different fluid contacts that capture the variability observed with the attribute extractions and well logs. The total GIIP is 91 BCF from summed estimations from REX A08 with 20 BCF and REX B01 with 70 BCF and STOIIP is 193 MBO. The stochastic modelling method was used as opposed to deterministic method because of sparse well distribution over the REX reservoir. SGS calculated stochastic realizations of the facies properties based on the upscaled definition of facies and variogram settings were based on the Niger Delta facies descriptions and layering.

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Variogram where spherical with a flattened sill of one (1) while sand, silt and shale facies showed various fractions in the modelled reservoir.

Reservoir A-04 was estimated for STOIIP using calculated GRV of (3632.18), NTG of (0.95), porosity of (0.30), oil saturation of (0.83), BO of (1.603), permeability of (7758) to give an average STOIIP of (4.33), the stock tank oil initially in place 0f 4.33 showed low prospectively. Reservoir A-08 was estimated for STOIIP (Table 4.21) using calculated GRV of (11970) NTG of (0.79) porosity of (0.29) oil saturation of (2.42) BO of (0.0048) permeability of (43560) to give an average GIIP of (20.13) the stored Gas initially in place showed high prospectively. Reservoir B-01 was estimated for STOIIP Table (4.21) using calculated GRV of (33761) NTG of (0.94) porosity of (0.29) oil saturation of (0.83) BO of (0.0048) permeability of (43560) to give an average stock tank oil initially in place (STOIIP) of 71.44 showed high prospectively. Reservoir B-04 was estimated for STOIIP (table 4.22) using calculated GRV of (95620.33) NTG of (0.96) porosity of (0.28) oil saturation of (0.78) BO of (1.603) permeability of (7758) to give an average stock tank oil initially in place (STOIIP) of (98.76) which showed high prospectively. Reservoir B-05 was estimated for STOIIP using calculated GRV of 75411. NTG of 1 porosity of 0.29 oil saturation of 0.88, BO of 1.4, permeability of 7758 to give an average STOIIP of 110Mbo the stock tank oil initially in place (table 4.23) showed high prospectively.

5.0. CONCLUSION

Seven wells were correlated, and six petroleum reservoirs identified and petrophysical evaluation of properties of porosity, water saturation and Net-to-gross are used to ascertain pay properties and petrophysical models. Volumetric of the oil and gas reservoirs evaluated the and the stock tank oil initially in place(STOIIP) and the Gas initially in place (GIIP), was summarized at 190mbo and Non-Associated Gas (NAG) GIIP volumes were estimated to be a total of 90.8 BCF. it concluded that evaluation of reservoirs in REX Field will be better understood by carrying out a reservoir compartmentalization study which puts in consideration the internal architecture of the reservoirs. The petrophysical and Geostatistical evaluation of the gas potential should be fully explored in future field development programs considering the evaluated GIIP.

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