Middle-East Journal of Scientific Research 2 (3-4): 107-110, 2007
ISSN 1990-9233

Formation Evaluation of Oshioka Field Using Geophysical Well Logs

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Abstract: The formation evaluation of Oshioka field was performed to identify hydrocarbon bearing reservoir and study reservoir properties based on data from the two wells. This was carried out with Petrel and Hydrocarbon Data System (HDS) Log analysis Software packages. The two wells contained sufficient data to allow detailed analysis, including porosity, water saturation, permeability and net-to-gross. The consistency of the results was however checked using mud logger and geological information.

Key words: Porosity · Permeability · Saturation · Lithology · Density and Neutron logs

INTRODUCTION

The formations in the Niger Delta-Nigeria consist of sands and shales with the former ranging from fluvial (channel) to fluviomarine (Barrier Bar), while the later are generally fluviomarie or lagoonal. These Formations are mostly unconsolidated and it is often not feasible to take core samples or make drill stem tests [1]. Formation evaluation is consequently based mostly on logs, with the help of mud logger and geological information as in this study. Petrophysical parameters like the lithology, fluid content, porosity, water saturation, hydrocarbon saturation and permeability were derived; from the well log data. The field of study lies in the South` of Delta state in the Niger Delta between longitude 5°35^1 E and 5°44^1 N and latitude 6°42^1 W and 5°23^1 S. It lies within the oil prolific belt of Niger Delta.

Three major lithostratigraphic units have been recognized in the Niger Delta [2-4]. These are the Akata, Agbada and Benin formations. Details of the geology of the Niger Delta has been discussed by several authors, [2, 5-8].

The Benin formation, which is a loose fresh water bearing sand with occasional lignite and clay and going up to 2,286 m deep with no over pressures. The Agbada formation is made up of alternation sands and shales. The sands are mostly encountered at the upper parts while Shales are found mostly at the lower parts. The Agbada formation is thickest at the centre of the Delta and goes up to 457.2 m. This is the seat of most oil reservoirs and center of over pressures.

Formation evaluation in the area of study within Niger Delta basin will allow an estimate to be made of porosity, fluid content and type and lithology. The physical and chemical properties of the rock determined in this way are an invaluable aid to describing sub-surface geology [1].

In the evaluation of a clastic reserviour,the presence of clay particles or shale within the sand is a parameter which must be considered. Shaliness is known to affect both formation characteristic and logging tool response. Carbonates, non-clastic reservoirs, are characteristically limestone

and dolomite. Their importance as reservoirs rocks should not be under estimated. Approximately, 50% of hydrocarbon reservoir are carbonate rocks [5]. Well logging tools respond primarily to the chemical nature of matrix and pore fluids.

In his pioneering work Archie [9] sets out the fundamentals of rock- type classification.Any porous network is related to its host rock fabric,therefore petrophysical parameter, such as porosity (θ), permeability (K) and saturation (S), for any given (type of rock) are controlled by pore sizes and their distribution and interconnection. The goal of reservoir characterization is to predict the spatial distribution of such petrophysical parameter on a field scale. Archie [9] stated that a broad relationship exists between porosity and permeability of a formation. Petrophysics also refer to the careful and purposeful use of rock physics data and theory in the interpretation of reservoir geophysics observation [10].

This paper aimed at computing and evaluating the petrophysical parameters of two onshore fields in the Niger Delta using geophysical well log data. The consistency of the results was however checked using mudlogger and geological information.

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The Niger delta oil province is characterized by approximately east-west trending synsedimentary faults and fold, [5]. These synsedimentary faults are called growth fault and the anticlines associated with them are called roll-over anticline [11].

MATERIALS AND METHODS

Well log correlation and formation evaluation analysis were carried out using Gamma ray, spontaneous potential, resisitvity, caliper, sonic, Neutron and Density logs. The top of the reservoirs were defined using stratigraphical approach. Stratigraphic marker beds were used to delineate the parameter intervals (reservoir sands) from the logs and were correlated across the field. The deeper pay sands in both well were correlatable while the shallowest pay sands in OGH 01 faulted out in OGH02. Table 1 show correlatable sand within the reservoir units seen across wells. The reservoir fluids were characterized using a combination of Neutron-porosity and Bulk Density logs. The mudlogger`s show description was however used to characterize sand K fluid due to the non-availability of neutron-porosity and Bulk density logs at that depth.

Table 1: Correlation Sand Units Across the Wells

Sands	OGH – 01TOP – BASE (MD ft)	OGH – 02 Top – Base (MD ft)
A	9501 – 9513	
B	9543 – 9558	
C	9574 – 9592	
D	9853 – 9940	9702 – 9808
E	10016 – 10048	9868 – 9898
F	10056 – 10145	9905 – 10006
G	10151 – 10190	10014 – 10056
H	10414 – 10445	10224 – 10244
I	10499 – 10513	10359 – 10375
J	10543 – 10589	10397 – 10445
K	11270 – 11310	11098 – 11142

Table 2: Vsh and Porosity Cut-offs

	parameters	
Sands	Vsh	Porosity
A	0.70	0.10
B	0.60	0.15
C	0.70	0.10
D	0.70	0.10
E1	0.38	0.10
E2	0.40	0.11
F	0.60	0.10
G	0.52	0.10
H	0.42	0.10
I	0.50	0.10
J	0.25	0.10
K	0.20	0.20

The fluid contacts for the reservoir, OWC and ODT were used to demarcate the basal extent of the hydrocarbon column in the reservoirs. These contacts were determined using the Resisitvity logs and a combination of neutron–porosity and Bulk Density logs. Edited input well logs data were used to generate rock properties with the aid of log calculator in the petrel software. The petrophysical results for both wells is shown in Tables 3 and 4.

The Gamma ray index option was employed to determine the percentage of shale and implicitly, the dominant lithology. This was achieved by determining the clean sand line from Gamma ray logs. Correction was made on the Gamma ray index to compensate for the unconsolidated sand of the Niger Delta (Tertiary). The volume of shale was calculated using the Equation below. The parameter also served as an input data in the porosity and saturation model for shaly sand.

Table 3: Petrophysical Results for Oshioka 01

Sands									
Parameter	A	B	C	E	H			J	K
Top MD (ft)	9501	9543	9574	10016	10414			10543	11270
Base MD (ft)	9513	9558	9592	10048	10445			10589	11310
Gross Thickness (ft)	12	16	18	32	31			46	40
Net Thickness (ft)	9	15	16	29	23			46	40
Contact (TVDSS)	ODT 9449	ODT 9495	OWC 9519	ODT 9984	OWC 10361			ODT 10527	ODT 11248
ϕ_{eff} (%)	21	24	26	21	Z1 17	Z2 15	Z3 19	20	25
Perm (md)	35	126	173	149	72	2	74	98	165
S_w (%)	72	41	42	28	36	1	1	23	32
NTG (dec)	0.75	0.93	0.89	0.91	0.74	0.07	92	1	1

Z = Zone

Table 4: Petrophysical Results for Oshioka 02

Sands									
Parameter	D					E	F	G	I
Top (ft)	9702					9868	9905	10014	10359
Base MD (ft)	9808					9898	10006	10056	10375
Gross Thickness (ft)	106					30	101	42	16
Net Thickness (ft)	67					27	93	40	14
Contact (TVDSS)	ODT 9718					ODT 9834	OWC9 850	OWC9 964	ODT 10311
ϕ_{eff} (%)	Z1 21	Z2 16	Z3 21	Z4 18	Z5 25	22	22	24	23
Perm (md)	60	0.9	62	9	205	129	50	89	36
S_w	39	71	39	57	32	27	31	36	52
NTG (dec)	0.92	0.06	0.96	0.28	0.97	0.9	0.92	0.95	0.88

Z=Zone

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

$$V_{sh} = 0.083x2\ 2^{3.7(vsh)} - 1.0 \quad (2)$$

where,

Gr_{log}	=	GR of formation measured from log
Gr_{min}	=	Least GR in zone of interest
Gr_{max}	=	Maximum GR reading in formation of interest
Igr	=	Gamma Ray Index
V_{sh}	=	Volume of Shale

The porosity was estimated from the density log. The effective porosity was further deduced by introducing the shale volume percentage into the equation.

Porosity was however determined for sand K using sonic log (Raymer-Hunt equation) because of the non – availability of density and neutron logs. The equation below were used for porosity estimation.

$$\phi_D = \frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_{fluid}} - \frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_{fluid}} V_{sh} \quad (3)$$

$$\phi = C \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{log}} \quad (4)$$

where,

ϕ_D	=	Density Porosity (effective)
ϕ	=	Sonic Porosity (Raymer –Hunt equation)
ρ_{ma}	=	Matrix Density
ρ_{log}	=	Bulk Density Log reading
ρ_{fluid}	=	Density of Fluid
ρ_{Vsh}	=	Density of Adjacent Shale
V_{sh}	=	Volume of Shale
Δt_{log}	=	Sonic Log Reading
Δt_{ma}	=	Interval Transit Time of the Matrix Material
C	=	Empirical Correlation Factor

Water saturation in all the sands was calculated form Archie equation except for sand D and H where Simandoux equation was used for correct estimation in a dirty reservoir. The equations used in the calculation of water saturation are given as follows:

Archie Equation

$$S_w = \left(\frac{aR_w}{\phi^m R_t} \right)^{\frac{1}{n}} \quad (5)$$

Simandoux Equation

$$\frac{1}{R_t} = \frac{\phi^m S_w{}^n}{aR_w} + \frac{V_{sh} S_w}{R_{sh}} \quad (6)$$

where,

S_w	= Water saturation
ϕ	= Porosity
R_w	= Formation water resisitvity
a	= Tortuosity
m	= Cementation factor
n	= Saturation exponent
R_t	= Formation Resistivity
R_{sh}	= Shale Resistivity

Due to non-availability of conventional core data, the permeability for this study was predicted using empirical correlations. Wyllie and Rose equation was used to estimate for effective permeability of the reservoirs in all the sands.

$$K = \sqrt{\frac{250\,x\,\phi^3}{S_{wirr}}} \quad (7)$$

CONCLUSIONS

All the sand are fairly homogeneous within pay zone except sand D and H. Because we can correlate the intermediate shale marker between the two wells in these sands, we believe it is sufficiently continuous to act as hydrocarbon flow baffle. Sands D and H were therefore divided into five and three flow units respectively, capturing changes in geological description and variation in petrophysical properties. These flow units were delineated using well tops (data from petrophysical evaluation) showing alternation of sand and shale.

Since the flow units are dictated by pore-throat size and local geologic changes, the calculated porosity and gamma ray log were the basic attributes used for a (quick look) subdivision. The two wells were found to be almost homogenous, implying that wells in the reservoir are in communication. The analysis of the GR and SP logs shows that the overall lithology is an alternating sequence of sands and shales. Our calculations indicate that porosity, permeability values from the hydrocarbon bearing reservoir are good enough for commercial accumulation in the Niger Delta.

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