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Formation Evaluation of an Onshore Oil Field, Niger Delta Nigeria.

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Abstract: *The formation evaluation of an onshore oil field has been carried out. Suite of geophysical logs comprising gamma ray, resistivity, density and neutron from five oil wells were used. Alternation of sandstone and shale lithologies were delineated within the interval logged which is typical of the Agbada Formation in the Niger Delta. A total of five reservoirs (W400, W500, W600, W700, W800) were observed in the five. The hydrocarbon fluid types were differentiated with the aid of density and neutron logs ran on the same track. The topmost reservoir (W400) is dominated by gas while the other reservoirs are mainly oil bearing. The computed average porosity and water saturation of the reservoirs ranges from 0.19 to 0.227 and 0.19 to 0.286 respectively. The permeability of the reservoirs ranges from 516 to 1662 mD.The Net to Gross ratio for the five reservoirs varies from 0.844 to 0.947. The computed values of the petrophysical parameters show that the five reservoirs have very good to excellent quality and the field has a good hydrocarbon potential.*
Keywords:*Formation Evaluation; Porosity, Permeability, Reservoir, Niger Delta.*

I. Introduction

Geoscientists use wireline logging to acquire a continuous record of rock formation's physical and chemical properties in boreholes. Some of these properties are density, gamma ray, resistivity, interval transits time and the size of boreholes. Other formation properties such as hydrocarbon saturation, permeability, net to gross ratio, formation porosity and shale volume are derived from the measured properties (Telford et al., 1990; Rider, 1986).These measured and derived properties are very important in the hydrocarbon industry. Most decisions on oil exploration and production are based on the results of derived properties of the reservoir. Geophysical logs are also used for correlating zones of interest across boreholes and for structural isopach mapping, the identification of geological formations, formation fluids, correlation between wells, evaluation of the productive capabilities of reservoir formations (Picketh, 1970; Ekine and Iyabe, 2009; Asquith and Krygowski, 2004).Many researchers have worked on the petrophysical analysis of different oil fields using geophysical logs in the Niger Delta (Adeoye and Enikauselu, 2009;Aigbedion and Iyayi, 2007; Imaseum and Osaghae, 2013 and Omoboriowo, 2012). There will be a continuous improvement of the petrophysical analysis technology because of its importance in the oil industry. The objectives of this research are to delineate and evaluate reservoir and petrophysical properties in five oil wells.

II. Summary of The Geology of the Study Area

The studied area is located in parts of the onshore zone in the Niger Delta sedimentary basin, Nigeria (Fig. 1). Niger Delta is the youngest sedimentary basin within the Benue Trough system. Its development began after the Eocene tectonic phase. The thickness of the basin ranges between 10-12km and it is made up of deltaic and shallow marine sediments mainly supplied by rivers Niger and Benue (Doust and Omatsola, 1990).
Three distinguished lithostratigraphic units namely Akata, Agbada and Benin Formations are present in the Niger Delta. The Akata Formation is predominantly marine shales and it is the main source rock in the basin (Stacher,1995; Kulke, 1995; Klett et al., 1997). The Akata formation is over pressured and it is overlain by the paralic sand/shale sequence of the Agbada Formation. The Agbada Formation is the main reservoir rock in the Niger delta. The Benin Formation is the topmost lithostratigraphy and it is a continental deltaic sands. The Niger Delta basin is characterized with shale diapirs, growth faults and associated rollover anticlines. Both structural and stratigraphy traps are common in the basin (Doust and Omatsola, 1990; Ekweozor and Daukoru, 1994).

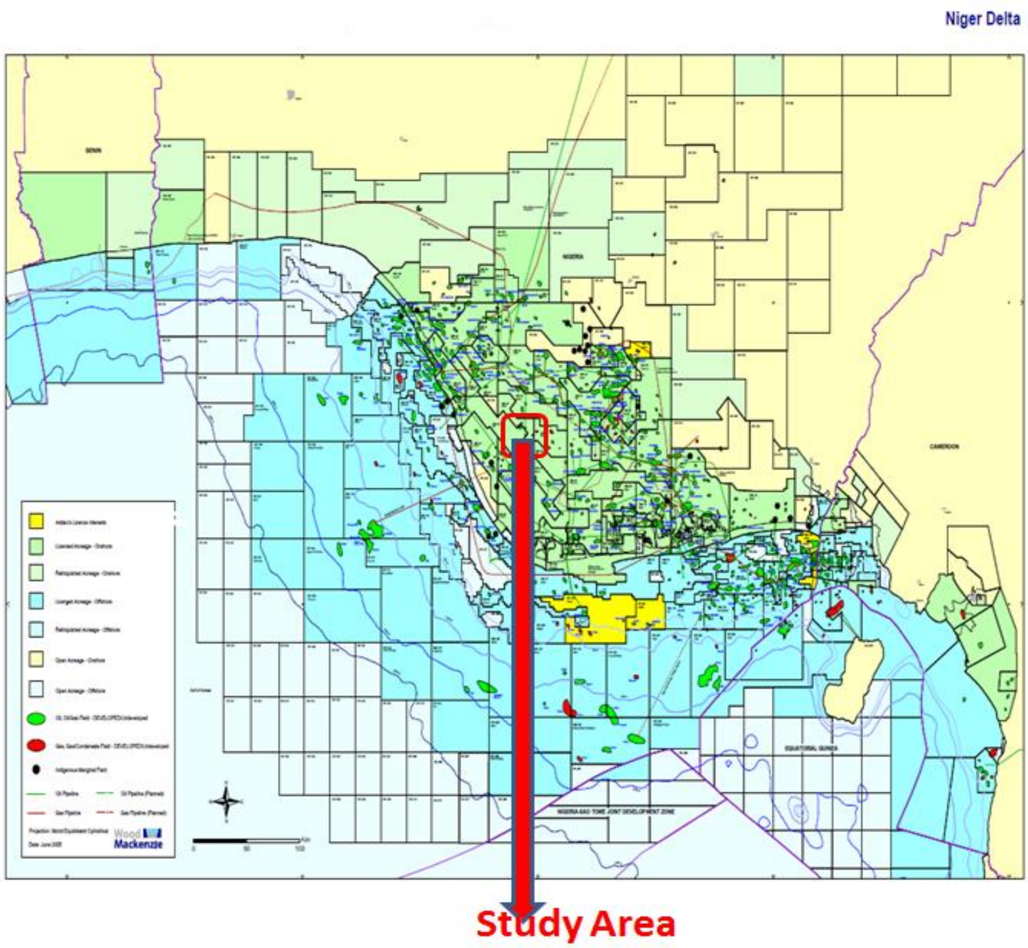


Fig. 1: Map of Niger Delta showing the Location of the studied Area

III. Materials And Methods

The materials used for this work are suite of well log data from five wells. The logs were acquired for Agip Nigeria Oil Development Company by Schlumberger. The physical properties of the rocks penetrated by the borehole were measured by a sonde, which is lowered down the borehole on a multiconductor electric cable. The various physical properties were measured as the sonde is drawn up to the surface of the earth. The value of the measurement is transmitted through the cable and plotted continuously against depth in the well on a magnetic tape in a recording unit. The composite logs include; gamma ray, density, neutron and deep resistivity. The gamma ray log measures the natural radioactivity of the formation and so it was used for differentiating shale and sand lithologies. The density log records the bulk density of the formation while the resistivity log measured the resistivity of the formation and so it was used for identifying fluid type. The petrophysical parameters needed for the formation evaluation were computed from the measured physical properties. The research methodology adopted for this work involves:

Determination of Porosity

Porosity can be determined from the density, neutron and sonic individually. In this work, porosity was computed from the density log. The porosity is derived from the formula:

$$\varphi_D = \frac{\ell_{max} - \ell_b}{\ell_{max} - \ell_{fl}} \qquad 1$$

where

ℓ_{max} =density of rock matrix = 2.65 g/cm^3

ℓ_b = bulk density from log (g/cm^3)

φ_D = total Porosity from the Density log

ℓ_{fluid} = density of fluid occupying pore spaces (0.4g/ cm^3 for gas, 0.9g/ cm^3 for oil and 1.0 g/ cm^3 for water).
The porosity can be presented in fraction or percentage. The matrix density is obtained from core grain density computed from routine core analysis in the Niger Delta. The fluid densities are obtained from literature and they correspond with the values used in the basin.

Determination of shale volume

Hydrocarbon reservoir in most cases are associated with shale content. The volume of shale in a reservoir is derived from gamma-ray log. The gamma ray derived shale volumes are computed using the following formulas:

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \qquad 2$$

where,
I_{GR} = gamma ray index
GR_{log} = gamma ray reading of formation from log
GR_{min} = minimum gamma ray (clean sand)
GR_{max} = maximum gamma ray (shale)
The volume of shale was calculated from the gamma ray index by using the Larionov equation for tertiary rocks:

$$V_{sh} = 0.083\left(2^{3.7X I_{GR}} - 1.0\right) \qquad 3$$

where,
V_{sh} = volume of shale
I_{GR} = gamma ray index.

Determinationof Net- To-Gross

Measure of the productive part of a reservoir is expressed either as a percentage of the producible (net) reservoir within the overall (gross) reservoir packages or sometimes as a ratio. Net-to-Gross can vary from just a few fraction to 1. It could be expressed as:

$$\text{Net-to-Gross} = \frac{\text{Net Thickness} * 100\%}{\text{Gross Thickness}} \qquad 4$$

where,
Net Thickness = Gross thickness – Shale thickness

Estimation of water and Hydrocarbon saturation

Determination of water saturation is essential in formation evaluation. The hydrocarbon saturation in the reservoir is normally calculated from the water saturation. The water saturation is obtained from deep resistivity log by using the formula:

$$Sw = \sqrt[2]{\frac{Ro}{Rt}} \qquad 5$$

where
Sw = water saturation
Ro = resistivity of the reservoir 100 percent saturated with saline water.
Rt = resistivity of the reservoir
The hydrocarbon saturation is the fraction of pore volume in a formation occupied by oil and gas. It is obtained by subtracting the computed water saturation in a reservoir from 1. The hydrocarbon saturation is given as:

$$Sh = 1 - Sw \qquad 6$$

where
Sw = water saturation
Sh = hydrocarbon saturation

Determination of Permeability

Several researchers have proposed various empirical relationships with which permeability can be estimated from porosity and irreducible water saturation. One of such relations was adopted in this work to estimate the permeability of the delineated reservoirs. The permeability equation is given as:

$$K = (79*\Phi^3/Sw_{irr})^2 \quad \text{for Gas} \qquad 7$$

and

$$K = (250*\Phi^3/Sw_{irr})^2 \quad \text{for Oil} \qquad 8$$

where

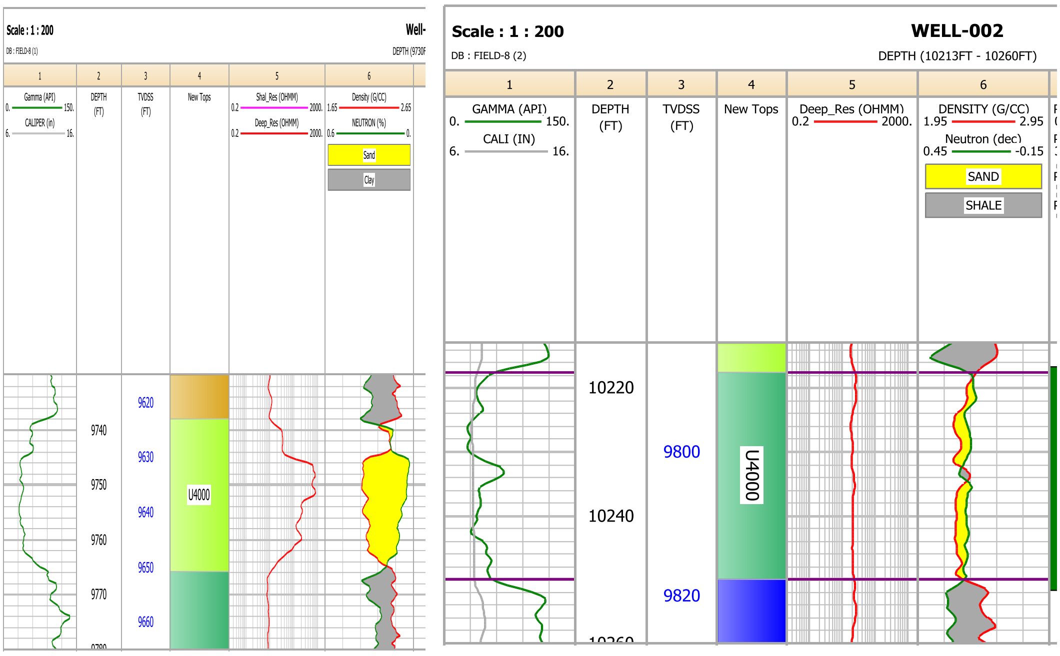
K = permeability,

ϕ = porosity

S_{wirr} = irreducible water saturation

IV. Results And Discussion

The qualitative interpretation of the gamma ray log revealed mainly alternation of sandstone and shale lithologies in the studied area. This is an indication that the depth range logged in the boreholes are within the Agbada Formation in the Niger Delta. Five reservoirs W400, W500, W600, W700 and W800 were identified and delineated from the gamma ray and resistivity logs. The correlation of four of the reservoirs in the five wells are shown in Figures. 2, 3, 4 and 5.



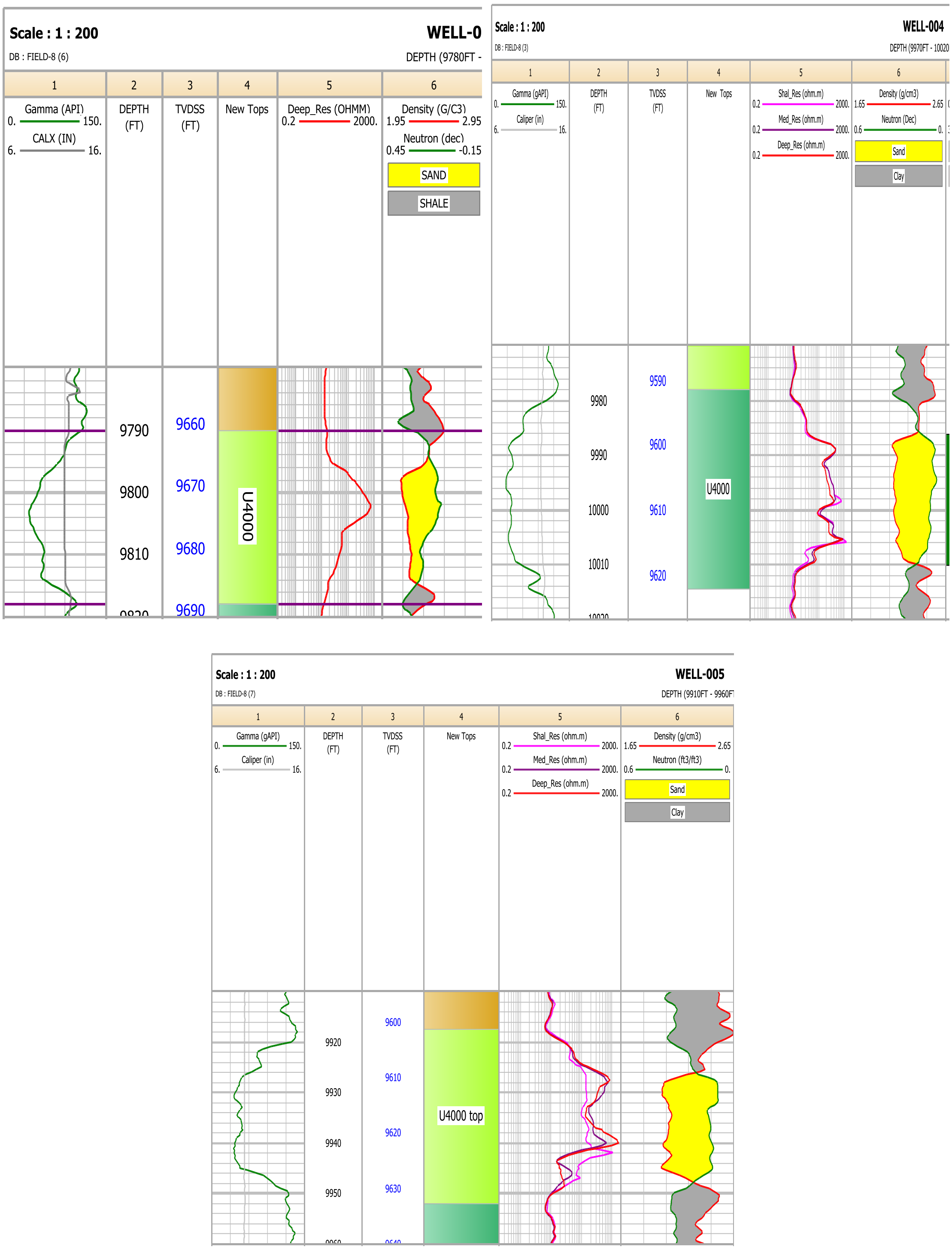
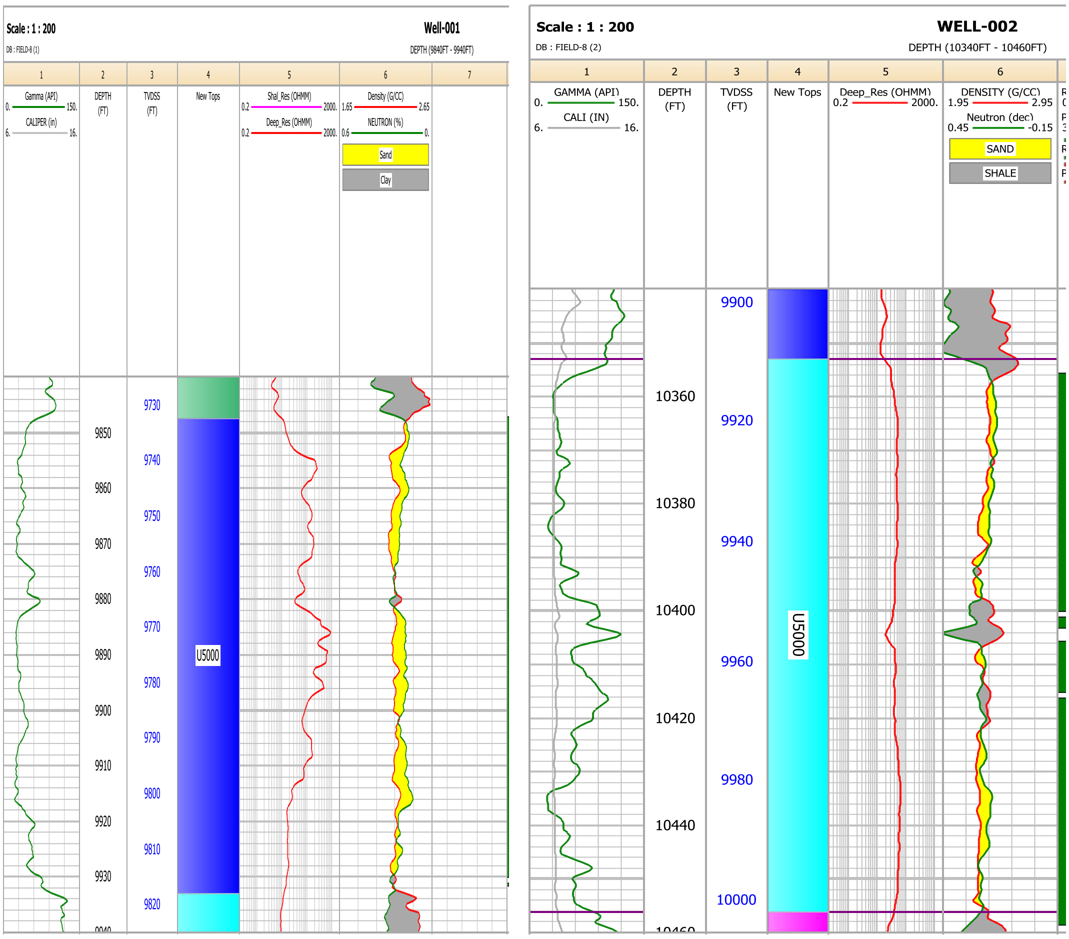


Fig. 2: Correlated Reservoir W400 across the Five Well


Scale : 1 : 200
Well-001
Scale : 1 : 200
WELL-002
DB : FIELD-8 (2)
DEPTH (10340FT - 10460FT)
GAMMA (API)
CALI (IN)
DEPTH (FT)
TVDSS (FT)
New Tops
Deep_Res (OHMM)
DENSITY (G/CC)
Neutron (dec)
SAND
SHALE
U5000

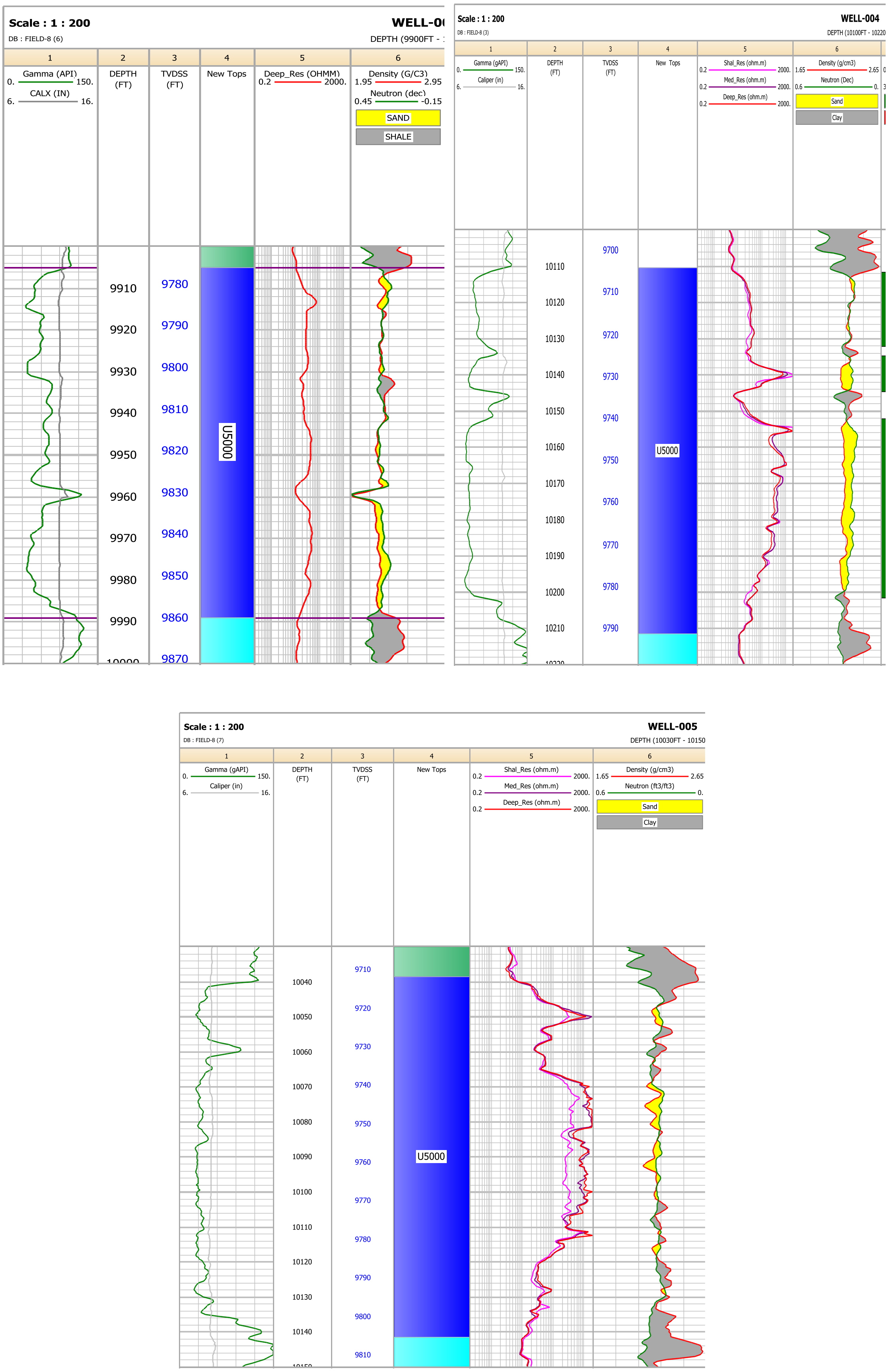
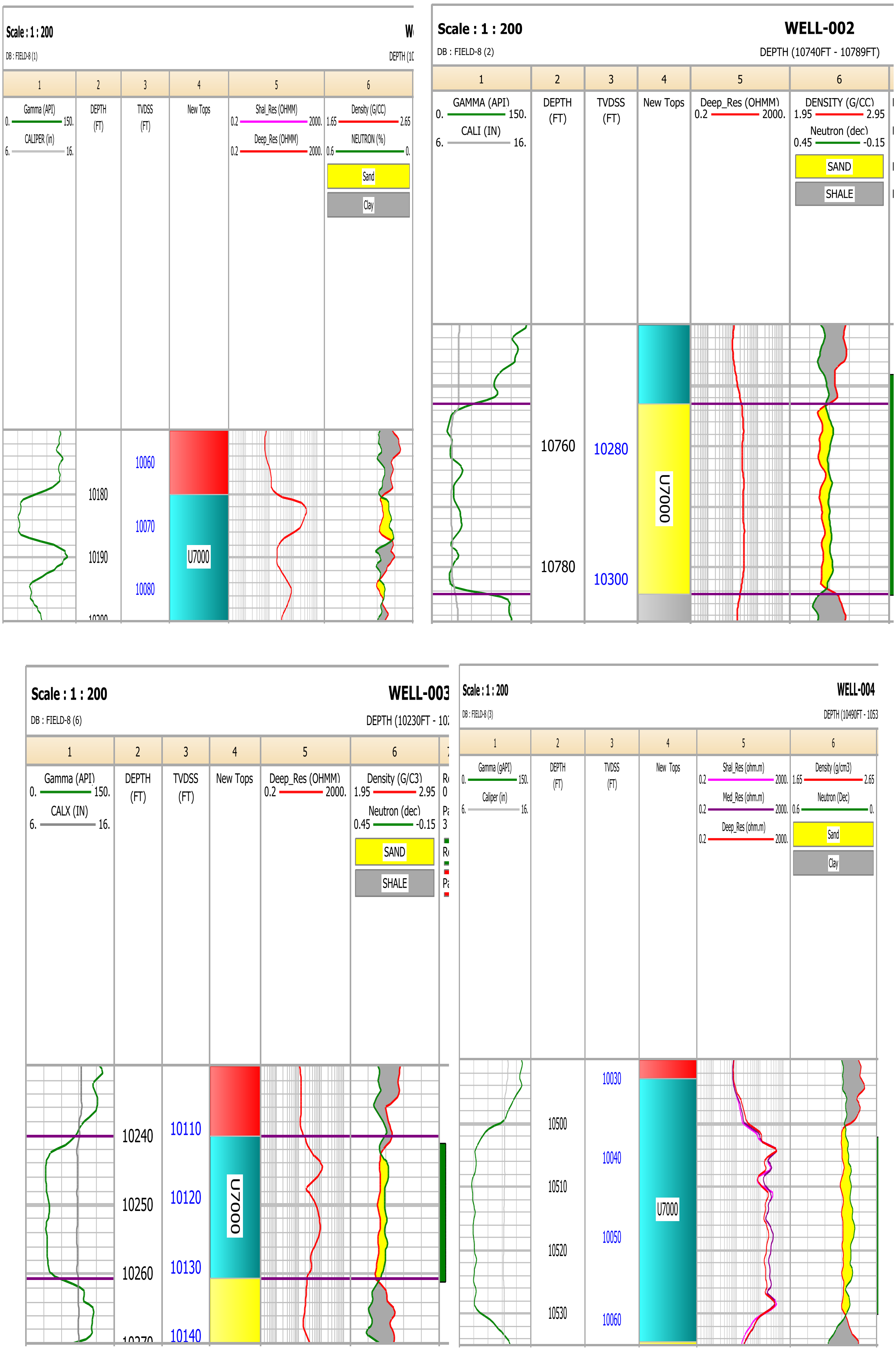


Fig. 3: Correlated Reservoir W500 across the Five Wells


Scale : 1 : 200
DB : FIELD-8 (1)
Gamma (API)
CALIPER (in)
DEPTH (FT)
TVDSS (FT)
New Tops
Shal_Res (OHMM)
Deep_Res (OHMM)
Density (G/CC)
NEUTRON (%)
Sand
Clay
10060
10180
10070
10190
10080
U7000
Scale : 1 : 200
WELL-002
DB : FIELD-8 (2)
DEPTH (10740FT - 10789FT)
GAMMA (API)
CALI (IN)
DEPTH (FT)
TVDSS (FT)
New Tops
Deep_Res (OHMM)
DENSITY (G/CC)
Neutron (dec)
SAND
SHALE
10760
10280
10780
10300
U7000
Scale : 1 : 200
WELL-003
DB : FIELD-8 (6)
Gamma (API)
CALX (IN)
DEPTH (FT)
TVDSS (FT)
New Tops
Deep_Res (OHMM)
Density (G/C3)
Neutron (dec)
SAND
SHALE
10240
10110
10250
10120
10260
10130
10140
U7000
Scale : 1 : 200
WELL-004
DB : FIELD-8 (3)
Gamma (gAPI)
Caliper (in)
DEPTH (FT)
TVDSS (FT)
New Tops
Shal_Res (ohm.m)
Med_Res (ohm.m)
Deep_Res (ohm.m)
Density (g/cm3)
Neutron (Dec)
Sand
Clay
10030
10500
10040
10510
10050
10520
10530
10060
U7000

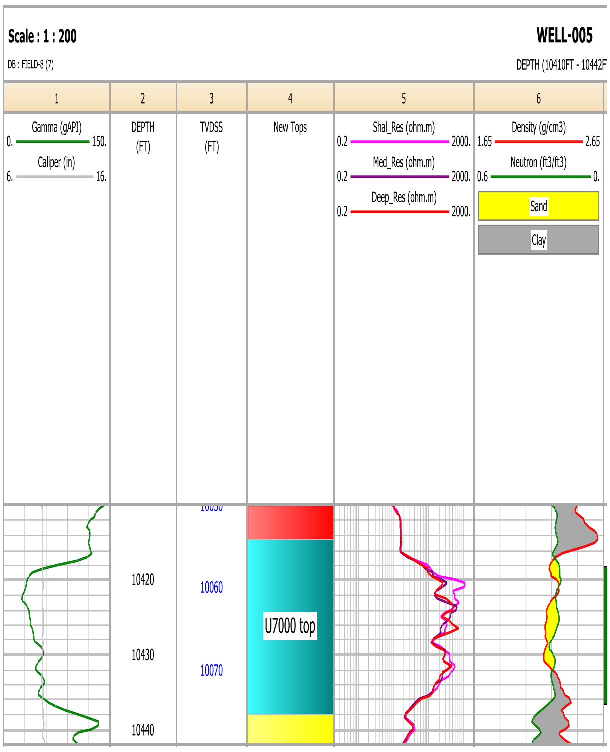
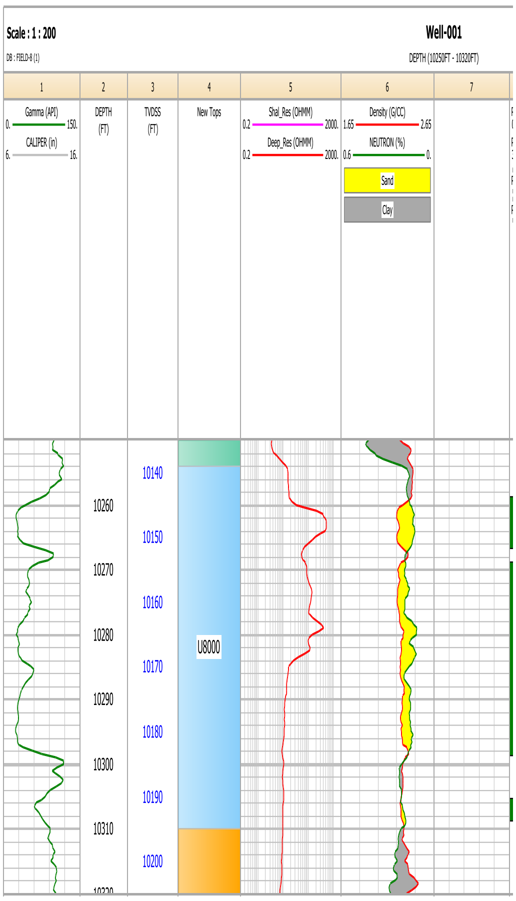
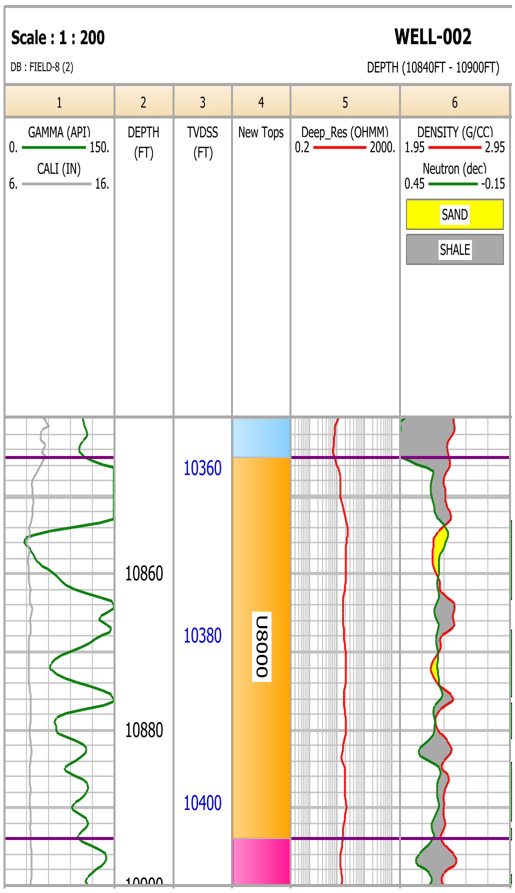


Fig. 4: Correlated Reservoir W600 across the Five Wells





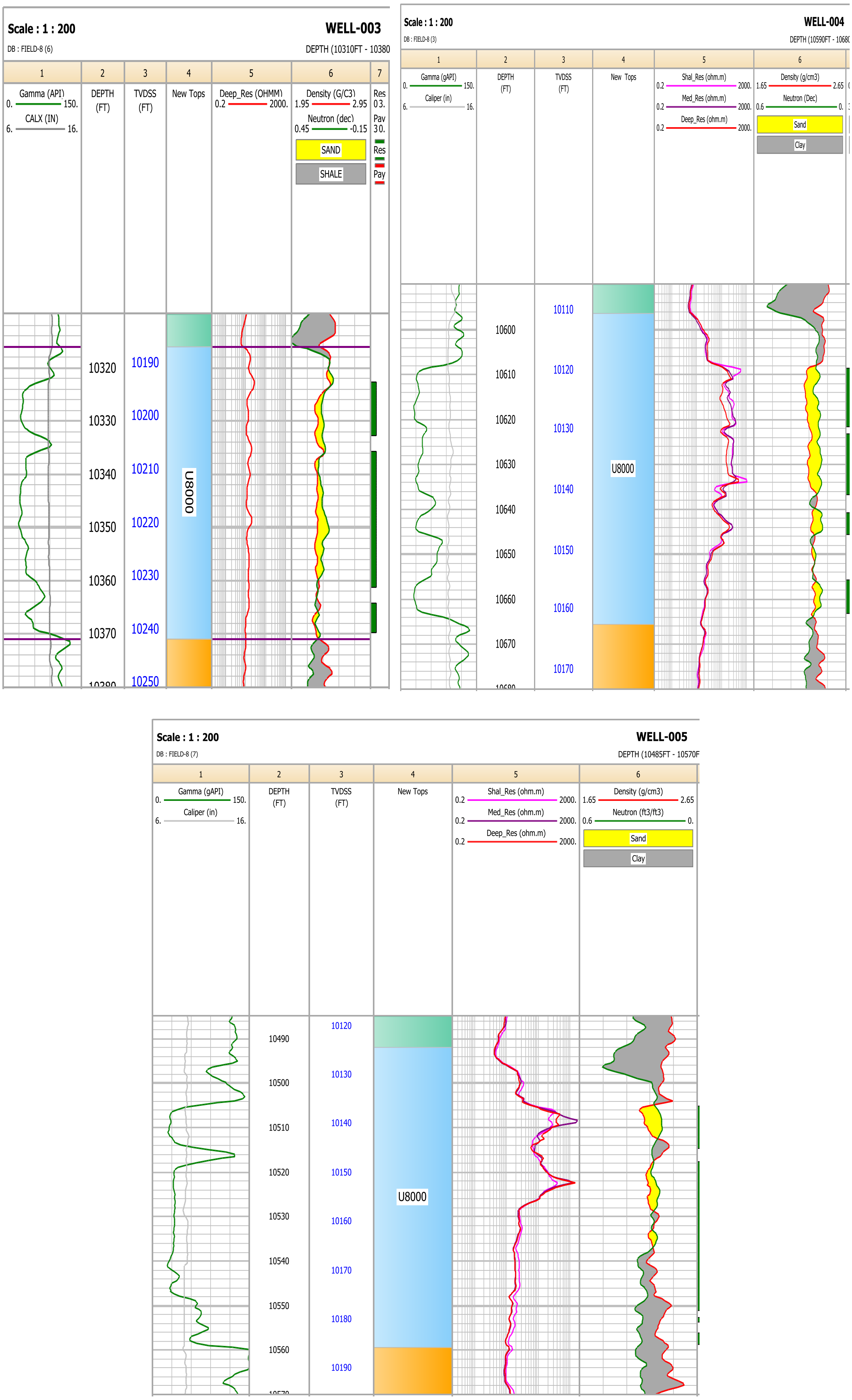


Fig. 5: Correlated Reservoir W700 across the Five Wells

The depth to top and thickness of the reservoirs vary from one well to the other. The plotting of the density and neutron logs on the same track was used for differentiating the hydrocarbon type in the reservoirs. The fluid distribution plot in the five reservoirs for the five wells are shown in Figures 6 -10 . The gas, oil and water in the reservoir are denoted with red, green and blue colours respectively. The average petrophysical parameters computed for each reservoir in the five wells are shown in Table 1. Reservoir W400 is saturated mainly with gas in well 1,4 and 5 while well 3 has both gas and oil and well 2 contain only oil. Reservoirs W500, W600, W700 and W800 contain mainly oil and water. The results of the petrophysical analysis show that the computed porosity for the five reservoirs varies from 0.19 to 0.227. The porosity decreases with depth and this can be attributed to compaction of the sediments.The result shows that the porosity of the reservoirs vary from good to very good. The average Net to Gross (NTG) for the reservoirs ranges from 0.844 to 0.947 which is an indication of a good quality reservoirs. The shale content in the reservoirs is minimal and the sandstone content is high. The calculated average water saturation for the reservoirs varies from 0.19 to 0.286 which implies that the hydrocarbon saturation varies between 0. 714 – 0.81. Hydrocarbon saturation in the reservoirs is very high. The computed average permeability ranges from 516 to 1662 mD. The average permeability of the reservoirs can be classified as very good to excellent.

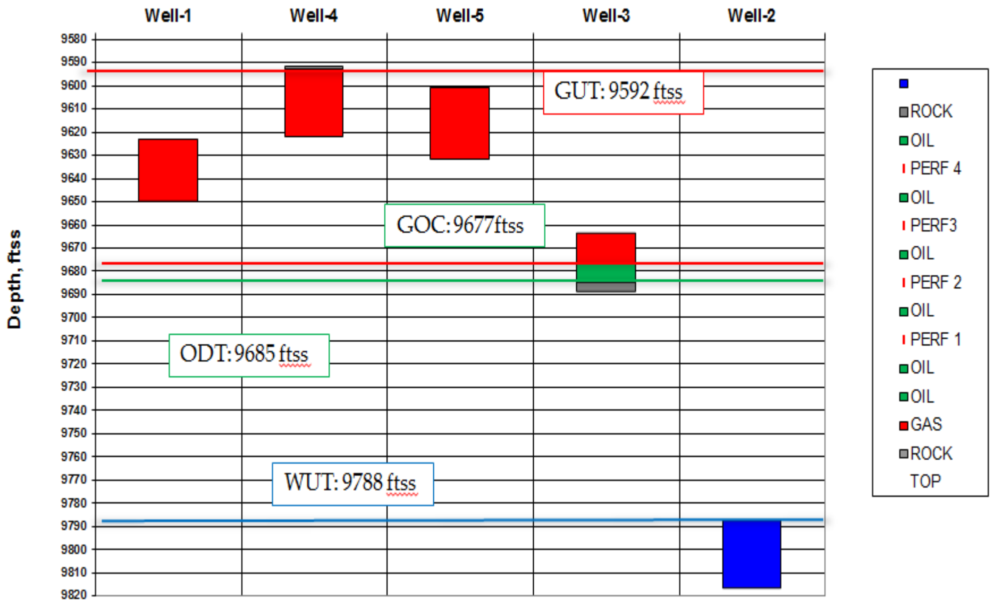


Fig. 6: W400 Reservoir Fluid Distribution Plot for the five wells

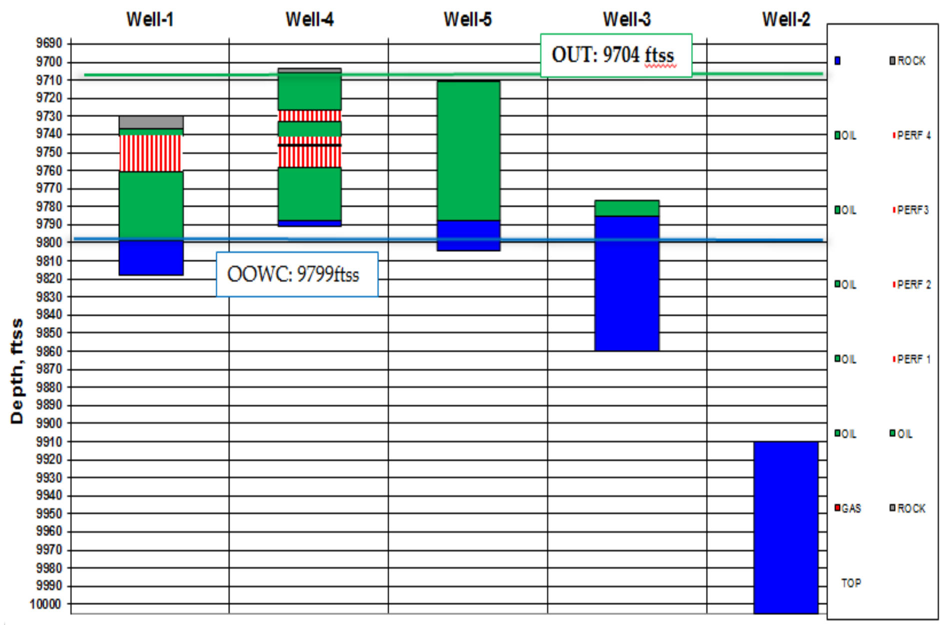


Fig. 7: W500 Reservoir Fluid Distribution Plot for the five wells

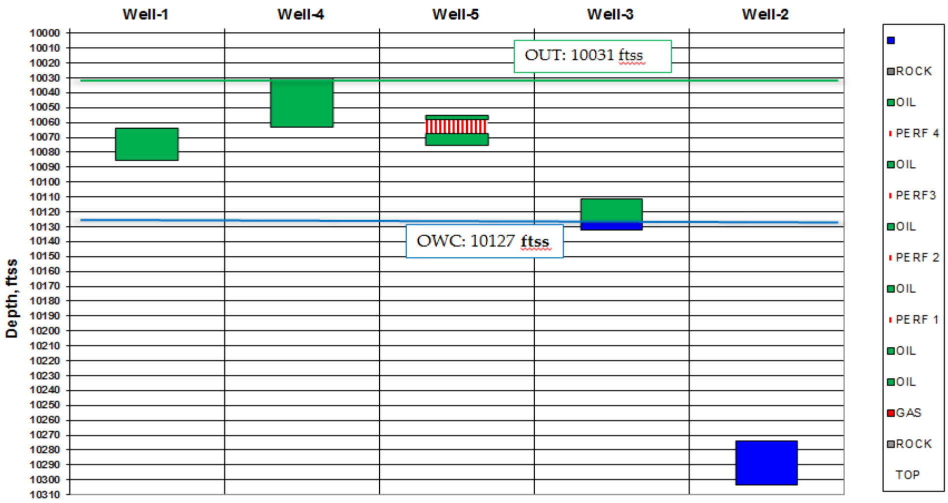


Fig. 8: W600 Reservoir Fluid Distribution Plot for the five Wells.

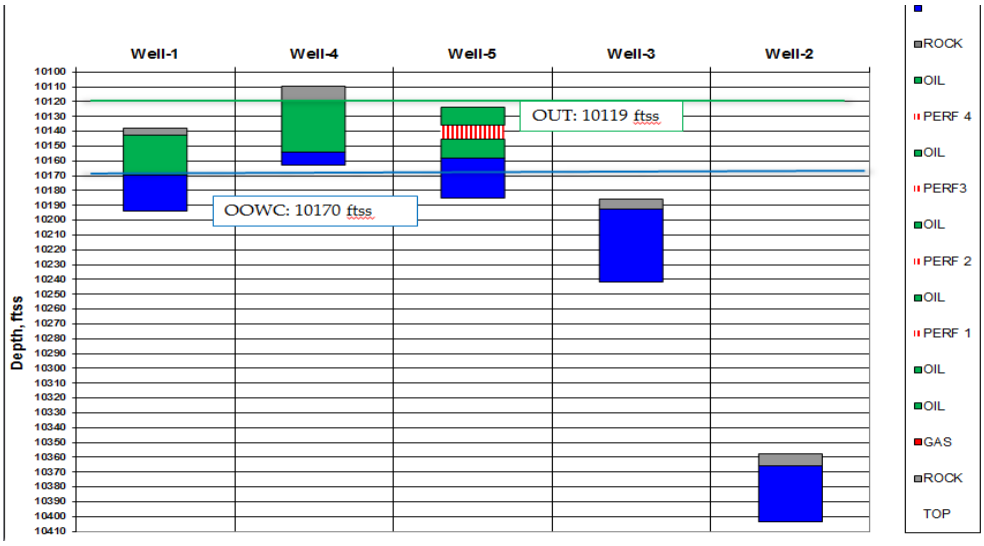


Fig. 9 : W700 Reservoir Fluid Distribution Plot for the five wells

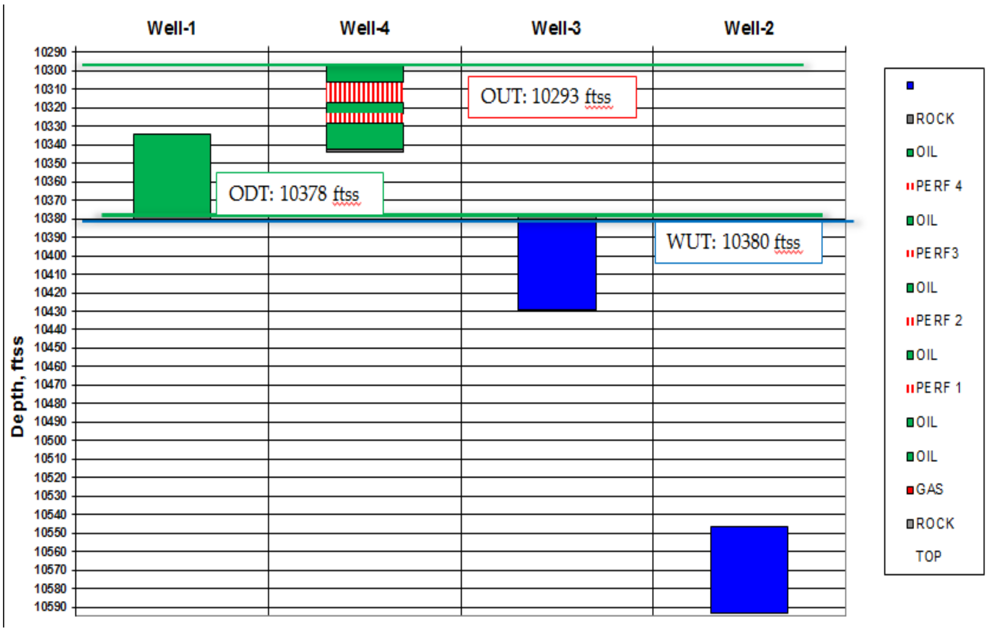


Figure 4.25:W800 Reservoir Fluid Distribution Plot

Table 1: Average Petrophysical Parameters Calculated for the Reservoirs

	Av porosity	NTG	AV Sw	Av Perm
U4000	0.227	0.844	0.286	1662
U5000	0.206	0.947	0.26	812.00
U6000	0.203	0.90	0.27	516.00
U7000	0.198	0.90	0.28	665.00
U8000	0.203	0.88	0.19	725

V. Conclusion

Formation evaluation is very crucial in reservoir studies. The results of the formation evaluation show that the studied oil field is characterized by alternation of sand and shale lithology. Five reservoirs were delineated and correlated across the five wells. Most of the reservoirs are oil bearing. The computed average porosity, water saturation, NTG and permeability are 0.20, 0.26, 0.89 and 827.67respectively. The reservoirs have very good and excellent petrophysical qualities. The studied oil field has good hydrocarbon potential. The results of the study have shown the importance of geophysical logs in hydrocarbon exploration and production.

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