Reservoir Characterization using well log data

Nasir Atallah Houady
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Mustafa Nazar Mohammed
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Sajad Shaker Yacoub
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Haider Ali Erzoki
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Moamel Ali Hamza
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Mohammed Mahdi
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Ali Sabeeh libiea
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

Abbas Jamal
College of Petroleum Engineering,
Al-Ayen University,
Thi-Qar, Iraq

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Abstract **—** In this research, In this research, formation evaluation were made for Mishrif formation in Nassiriya oil field using well logs data. Petrophysical interpretation such is (volume of shale, porosity, water saturation, net to gross calculation) was calculated using IP software. Some Petrophysical data from well log, such as: Resistivity logs Density log Sonic log Neutron log GR log. The well Ns-9 was selected to study the characterization of Mishrif reservoir and calculate petrophysical properties. Well logs data included (Gama ray log, Density and neutron, resistivity logs and sonic log) was uploaded to IP software. were combined. Porosity (Φ), fluid saturation (Sg, So, Sw), net thickness, of wells which These are the variables that determine the quality of the reservoir.

The aim of this paper is to use an integrated technique in computing various Petrophysical parameters, these techniques include using well log data and combining various mathematical equations which ranges from the linear, non-linear (Vsh Stieber) and the Archie's equations. The results shown that the Mishrif unit mB1 is the main reservoir in the formation, this unit recorded highest porosity and lower water saturation value

I. INTRODUCTION

Reservoir characterization is a term which integrates all available data to define the geometry, distribution of physical parameters, and flow properties of a petroleum reservoir. Reservoir characterization encompasses the understanding and methods used to characterize reservoir heterogeneity. Such information about the reservoir will help improve production rates, rejuvenate oil fields, predict future reservoir performance, minimize costly expenditure Reservoir characterization is an important phase between the discovery of an oil or gas field and the reservoir management phase.

Reservoir characteristics such as natural heterogeneity, spatial variability of permeability and porosity, porous media properties and spatial distribution of hydrocarbon and water predominantly control the flow field, reservoir performance. Reservoir characterization an interdisciplinary measure which integrates the application of geology, geophysics, reservoir engineering, petrophysics, economics, and data management. Well logs is one of the most significant method, used in oil and gas industry for reservoir characterization. Well logging is performed in the boreholes which are drilled for the oil and gas, mineral, groundwater and geo-thermal exploration. This method provide insight into the formations and conditions in the subsurface, aimed primarily at detection and evaluation of possibly production horizons and calculate the hydrocarbon volume, and many others. By using wireline log data, one may be able to calculate Shale volume (Vsh), Water saturation (Sw), Porosity (φ), Permeability (k). [2] To get a clear idea about a formation it must be evaluated Formation evaluation is the process that characterizes rock and fluid properties based on downhole measurements, formation testing, and laboratory analysis services. Petrophysical analysis uses a wide variety of measurements which leads to an understanding of the reservoir and its detailed characteristics. This process also determines the best means for their recovery. [3] The main objectives of reservoir characterization are the description and the characterization of the reservoir heterogeneities that control the fluid flow combined with geological and structural model of the reservoir.

II. GEOLOGY OF STUDY AREA.

Nasiriyah field is an oil field located in Dhi Qar Governorate, Iraq, about 38 km northwest of Nasiriya city. Discovered in 1973. Nasiriyah field is located in the NW-SE oriented Mesopotamian Zone extending across the alluvial plains of the Euphrates-Tigris valleys.

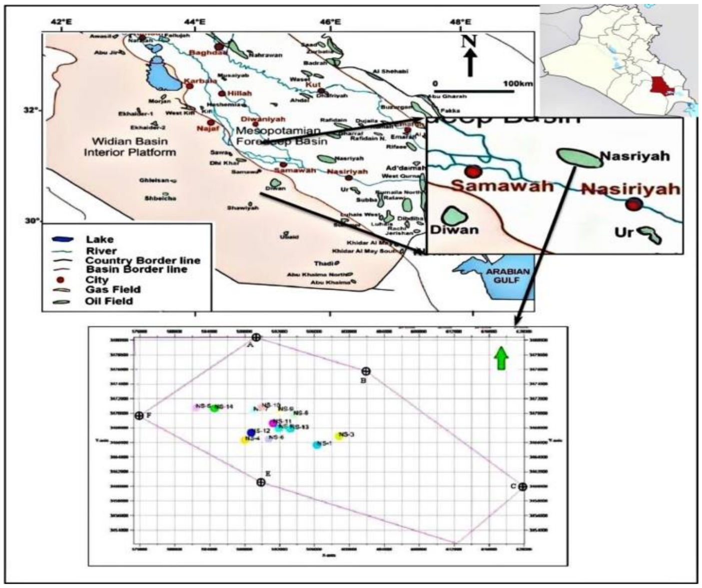

Fig (1) Nassiriyah oil field location map

III. Overview of Petrophysical properties.

The Petrophysical properties porosity, permeability, relative permeability, capillarity, and saturation. Pore-size distribution is presented as the common link between these properties.

A. Porosity

The rock texture consists of mineral grains of various shapes and sizes and its pore structure is extremely complex. The most important factors of the pore structure are how much space there is between these grains and what their shapes are. That is because the spaces between these grains serve to either mainly transport fluids forming connecting pores, or to store the fluids forming storage pores. From the reservoir engineering standpoint, porosity is one of the most important rock properties, a measure of space available for storage of hydrocarbons. Quantitatively, porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship , This important rock property is determined mathematically by the following generalized relationship:

$$\varphi = \frac{pore\ volume}{bulk\ volume} = 1 - \frac{grain\ volume}{bulk\ volume} \qquad (1)$$

bulk volume = grain volume + pore volume

Where φ = porosity

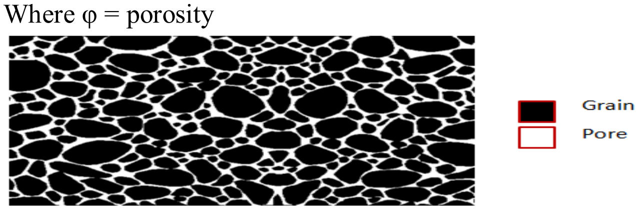

Figure 2: Microscopic Cross Section Image of a Porous Medium

As the sediments were deposited and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces by excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely:

- Absolute porosity
- Effective porosity

Absolute porosity: The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore interconnection. The absolute porosity is generally expressed mathematically by the following relationship:

$$\varphi_a = \frac{total\ pore\ volume}{bulk\ volume} = \frac{bulk\ volume - grain\ volume}{bulk\ volume} \qquad (2)$$

Where φ_a = absolute porosity.

Effective porosity: is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.

$$\varphi_e = \frac{interconnected\ pore\ volume}{bulk\ volume} \qquad (3)$$

Where φ_e = effective porosity.

It controls the magnitude of fluid flow and is a key parameter in the assessment of recoverable resources. However, its accurate measurement in tight formations is challenging, due to their complex pore structure and lithofacies heterogeneity.

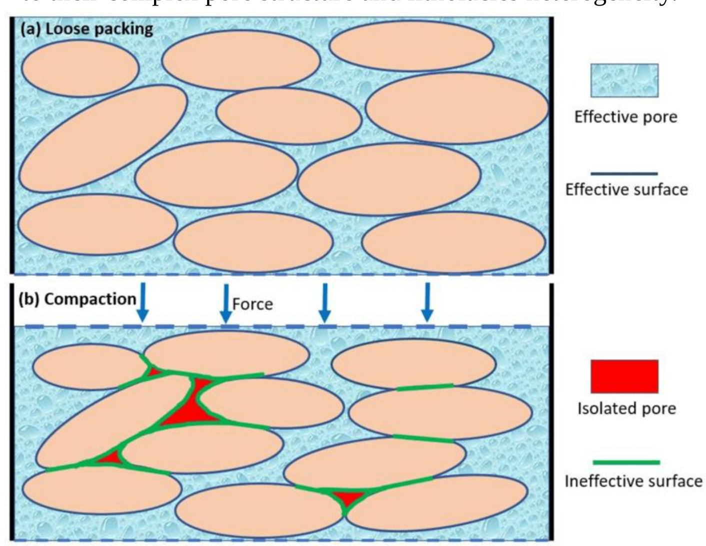

Figure 3: Illustration of the effective porosity and effective specific surface area when the compressible bed is under compaction (b) in contrast to the bed at loose packing condition (a).

B. PERMEABILITY

Permeability is the capacity of a rock layer to transmit water or other fluids, such as oil. The standard unit for permeability is the Darcy (d) or, more commonly, the millidarcy (md). The rock permeability, k, is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation. This rock characterization was first defined mathematically by Henry Darcy in 1856. In fact, the equation that defines permeability in terms of measurable quantities is called Darcy's Law.

Darcy's law originates from the interpretation of the results of the flow of water through an experimental apparatus.

Darcy developed a fluid flow equation that has since become one of the standard mathematical tools of the petroleum engineer. If a horizontal linear flow of an incompressible fluid is established through a core sample of length L and a cross-section of area A, then the governing fluid flow equation is defined as

$$\nu = -\frac{k}{\mu}\frac{dp}{dL} \tag{4}$$

where ν = apparent fluid flowing velocity, cm/sec
k = proportionality constant, or permeability, Darcys
μ = viscosity of the flowing fluid, cp
dp/dL = pressure drop per unit length, atm/cm

The velocity, in above Equation is not the actual velocity of the flowing fluid but is the apparent velocity determined by dividing the flow rate by the cross-sectional area across which fluid is flowing. Substituting the relationship, q/A, in place of in the Equation and solving for q results in :

$$q = -\frac{kA}{\mu}\frac{dp}{dL} \tag{5}$$

where q = flow rate through the porous medium, cm^3/sec
A = cross-sectional area across which flow occurs, cm^2

Permeability is measured by passing a fluid of known viscosity m through a core plug of measured dimensions (A and L) and then measuring flow rate q and pressure drop Dp. Solving above Equation for the permeability, gives:

$$k = \frac{q\,\mu\,L}{A\,\Delta p} \tag{6}$$

Where:
L = length of core, cm
A = cross-sectional area, cm^2
The following conditions must exist during the measurement of permeability:

- Laminar (viscous) flow
- No reaction between fluid and rock
- Only single-phase present at 100% pore space saturation

This measured permeability at 100% saturation of a single phase is called the **absolute permeability** of the rock.

C. Fluid Saturation

Water saturation is the ratio of the volume of water to the volume of pores and is denoted by the symbol (S) In determining the suitability of a reservoir for water flooding, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility that, in turn, gives higher recovery efficiency.

Gas saturation (Sg) = Vg / Vp (7)
Oil saturation (So) = Vo / Vp (8)
Water saturation (Sw) = Vw / Vp (9)

Total saturation of fluid is equation to 1, therefore this can mathematically be expressed like this

$$Sg + So + Sw = 1 \tag{10}$$

D. Lithology and Rock Properties

Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success are:

- Porosity
- Permeability
- Clay content
- Net thickness

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection Program will have only a minor impact on the matrix porosity, which might be crystalline, granular, or vugular in nature.
Although evidence suggests that the clay minerals present in some sands may clog the pores by swelling and deflocculating when water flooding is used, no exact data are available as to the extent to which this may occur.
Tight (low-permeability) reservoirs or reservoirs with thin net thickness possess water-injection problems in terms of the desired water injection rate or pressure. Note that the water-injection rate and pressure are roughly related by the following expression:

$$p_{inj} \propto \frac{i_w}{hk} \tag{11}$$

where p_{inj} = water-injection pressure
i_w = water-injection rate
h = net thickness
k = absolute permeability

The above relationship suggests that to deliver a desired daily injection rate of iw in a tight or thin reservoir, The required injection pressure might exceed the formation fracture pressure.

IV. Well Logging tools

A. Gamma ray:

The Gamma log is used to record the naturally occurring radiation found in the surrounding borehole rocks from three primary isotopes: Potassium-40 (K),Thorium (Th), and Uranium (U) .[5][6][7] Clays have the highest concentration of these radioactive isotopes. Other applications for the Gamma log include: estimating shale/clay content, identifying certain mineral deposits such as coal, potash, and uranium, stratigraphic correlations with other logs/seismic data and boundary estimation, and monitoring movement of injected radioactive materials. [6][8]

1) *The Gamma Log Tool:*

What is commonly known as the Gamma log, is actually differentiated into the 1) Gamma Ray log, and 2) the Spectral Gamma Ray log. The Gamma Ray log is the simpler of the two and only measures the total radioactive count rate in API units. Whereas the Spectral Gamma Ray log is able to differentiate between the different radioactive elements (K, Th, U) and outputs the abundance of each in parts per million (ppm). The Spectral Gamma Ray log is particularly useful when working in carbonate rocks; radioactivity caused by Th and K is linked to clay content while radioactivity caused by U can be associated with organic matter, diagenesis, dolomitization, or unconformities to name a few. [10][11]

2) *Shale Identification*

Shales are rocks made up primarily of compacted clays, and to a lesser extent silt and mud. Potassium commonly makes up ~2% of most shales, however because it is so abundant and reactive, it may also occur as clays in immature sandstones, or in large quantities ~10-50% in certain evaporites.[6][8][9] Potassium can only be moderately effective at identifying shales correctly. Thorium, however is insoluble and occurs in almost constant values in shales because of this property. A typical shale will have a Thorium range from 8-18 ppm, with Thorium contributing anywhere from 40-50% of the radioactivity. Unlike Potassium and Thorium, Uranium is not associated with clay minerals and thus occurs irregularly in shales. To summarize, a shale is typically associated with a high radioactivity made up primarily by Thorium, to a lesser extent Potassium, and a variable amount of Uranium.

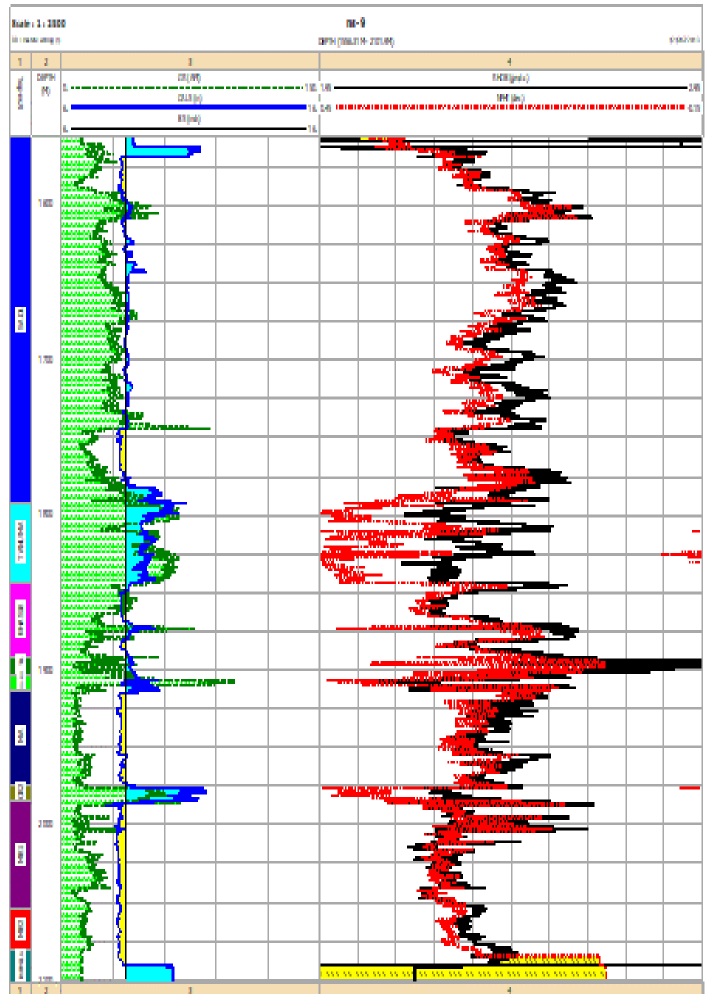

Fig 4: A relationship GR with neutron and density

B. Resistivity logs

Resistivity logging is a method of well logging that works by characterizing the rock or sediment in a borehole by measuring its electrical resistivity. Resistivity is a fundamental material property which represents how strongly a material opposes the flow of electric current. In these logs, resistivity is measured using four electrical probes to eliminate the resistance of the contact leads. The log must run in holes containing electrically conductive mud or water, i.e., with enough ions present in the drilling fluid. [12][13]
Resistivity is the property of a material that resists the flow of electrical current. Thereciprocal of resistivity is conductivity.
Resistivity is defined by the equation. [13]

$$R = \overline{r} * A / L \qquad (12)$$

Where:

R: is resistivity.

r: is resistance.

A: is cross-sectional area.

L: is length.

The resulting unit of resistivity is ohm meters squared/meters or simply, ohm meters (Ωm).[13][12] Resistivity is an independent property of a material and does not vary with size or shape of the material sample.[13]

Table 1: Material and their relative resistivity

Material	Relative Resistivity
Fresh water	High
Salt water (Brine)	Low
Hydrocarbons	High
Sandstone	High
Limestone	High
Shale	Low

1) *Resistivity Logging*

Resistivity logging is an electrical well logging method and as such should be conducted in an open/uncased hole. Usually resistivity logs are displayed ontrack 4 of a well log and are displayed in ohm meter (Ωm) units[12] Resistivity logging was the first rock property that was logged and began the development of well loggingmethods.[13]

2) *Measurement & Tools*

During logging, a current is produced within a formation and the formation's responseto the current is recorded. There are two ways that the current can be produced in the formation: i. directly applying a current into the formation, and ii. inducing a currentin the formation.

Electrode tools are used to directly apply a current to the formation and measure the resistivity. Induction tools are used to induce a current in the formation and measure the conductivity. Induction tools are more widely used but a combination of electrode and induction tools can be used to create a single log of resistivity in the various zones of the formation. Electrode tools generally measure the shallow resistivity whileinduction tools generally measure the deep resistivity. Deep induction tools usually run in the frequency range of 35 – 20,000 Hz.[13]

3) *Zones Measurements*

Resistivity logs are influenced by the fluid used during drilling. During drilling, the drilling mud seeps into the formation's pores and displaces the original formation fluid. The solid particles of the mud line the walls of the borehole while the filtrate is pushed into the formation. This creates various zones around the borehole based on how far the drilling fluid has been pushed into the formation.[13]

The invaded zone is the area where the drilling fluid is present in the formation. The invaded zone is comprised of the flushed zone and the annulus zone.

The flushed zone is only a few inches into the formation from the borehole and all of the original formation fluid has been replaced by drilling filtrate. The resistivity in the flushed zone reflects the resistivity of the drilling filtrate. The flushed zone is logged as shallow depth resistivity

The annulus zone is the transition zone next to the flushed zone and has a mixture of the drilling filtrate and the original fluid. The resistivity of the annulus zone reflects a combination of the drilling filtrate and original fluid. The annulus zone is logged as medium depth resistivity

The uninvaded zone is the furthest zone from the borehole and has not had any drilling fluid enter it. The resistivity in the uninvaded zone is the true resistivity of the original fluid and formation. The uninvaded zone is logged as deep resistivity.

C. Sonic log:

A sonic log produces data which illustrates P-wave travel time versus depth [14] and is recorded as microseconds per foot (ms/ft). This data provides information about how fast acoustic waves travel through rock. Wave propagation which produces the P-waves in sonic logs follow properties according to Snell's Law [15] and demonstrates how waves travel through different interfaces or rock layers in the subsurface. Snell's Law:

$$\frac{\sin\theta_2}{\sin\theta_1} = \frac{v_2}{v_1} = \frac{n_1}{n_2} \qquad (13)$$

Waves will propagate until attenuation, which can be a result of several situations. Some degree of absorption will affect waves, turning the mechanical energy into heat. Waves can also be attenuated by coming in contact with fracture or bedding planes and are internally reflected [15]. Another form of attenuation occurs whena foreign substance, usually gas, enters the mud column and decreases the sonic signal[17]. This type of attenuation, referred to as cycle skipping, can produce low quality logs (Figure 3[15]). All of these occurrences must be accommodated for when relating to seismic. Another characteristic to accommodate and correct for when analyzing sonic log data is tool stretch. As the wireline is lowered into the borehole, the weight of the line will cause some stretch that grows larger with increasing depth. This must be accommodated for especially when comparing sonic log data to core data.

1) *Dipole Shear Sonic Logs*

The most modern type of sonic logs are the dipole shear sonic logs. These logs measure values for compressional, shear, and Stoneley slowness through both monopole and dipole sources. A monopole source emits radially while a dipole energy source emits energy in one direction. When determining whether to use a monopole or a dipole measurement, the type of formation that the acoustic waves will be traveling through is most important[15].

A slow formation refers to a formation in which the compressional wave velocity measured in the borehole fluid exceeds encompassing shear wave velocities [14]. This monopole measurement results in compressional and Stoneley arrivals but no detected shear waves. Therefore, a dipole measurement is better suited for a slow formationbecause it can generate flexural or bender waves which produce measurable shear waves. An example of a slow formation is a high porosity gas sand layer.

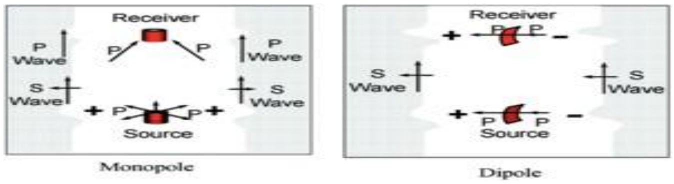

Figure 5: Monopole versus Dipole system

A fast formation has higher shear wave velocities than compressionalwave velocities. Shear waves as well as compressional and Stoneley waves can all be observed with a monopole measurement. An example of a fast formation would be a low porosity carbonate layer[15]. Although both monopole and dipole measurements have advantages for different types of rock layers, modern sonic logs contain both types of measurements as to most accurately measure the acoustic properties of the subsurface[18].

2) *Single Receiver Sonic Logs*

Single receiver sonic logs were the first type of sonic logs and contained only one transmitter and one receiver. These logs are no longer used unless additional data analysis methods are present; however, old data still remains in less updated files[15]. illustrates a time line of previous sonic logs that have since been outdated.

3) *Two Receiver Sonic Logs*

Soon after single receiver sonic logs, two receiver sonic logs became more commonly used in order to compensate for borehole effects[15]. Two receiver sonic logs are still in use but require a significant amount of editing before an evaluation can be made from the logs.

4) *Borehole Compensated Sonic Logs*

Borehole compensated sonic logs [19] have two sets of transmitters and receivers, which measure compressional waves and average the travel time [19]. This type of log automatically compensates for variations in the borehole diameter or size and sonde tilt, as well as, increases resolution from 2 feet to 9 inches[15].

5) *Array Sonic Logs*

This type of sonic log can have botha monopole or dipole source. Similar Array sonic logs were developed to provide information about a variety of acoustic to the dipole shear sonic log, the array sonic log with a monopole source measures compressional, Stoneley, and wave velocities which are used to estimated shear wave velocities. The monopole source is not able to measure shear wave velocities in slow formations. In fast formations, the monopole source is able to measure compressional, shear, and Stoneley waves. The dipole source produces a more consistent and accurate shear wave velocity for both slow and fast formations[15]

D. Density log

The formation density log is useful for determining the porosity of a logged interval. The porosity is given By

$$\Phi = \frac{\rho_{\mathrm{ma}} - \rho_{\mathrm{b}}}{\rho_{\mathrm{ma}} - \rho_{\mathrm{f}}} \quad (14)$$

where ϕ is porosity, and ρma, ρb and ρf are rock matrix, bulk and fluid densities.

The density log measures electron density by detecting gamma rays that undergo Compton scattering. The intensity of scattered gamma rays is proportional to electron density. Electron density is the number of electrons in a volume of the formation. Electron density is proportional to bulk density.

The density log is based on gamma ray scattering as a function of the bulk density of the irradiated matrix. The bulk density is the overall density of the matrix and the fluids (water, oil, gas) within the pores. A gamma ray source irradiates a stream of gamma rays into the formation, some of which are adsorbed, some passed on through the matrix, and some scattered. The ability of the matrix to attenuate the gamma rays is recorded as the intensity of scattered gamma rays arriving at two fixed distances from the gamma ray source. Bulk density is determined by a correlation between the gamma ray intensity at the detectors and data used for calibration of the tool. The gamma ray intensity arriving at the detectors is an inverse function of the bulk density.

The density log tool is sometimes referred to as a compensated density log that measures the matrix bulk density with compensation for effects due to the thickness of the mud cake and borehole irregularities. The recorded log has a linear scale of bulk density (g/cm3). A second curve is included that shows the degree of compensation that was applied, and a caliper log is included with the density log survey

The total density (bulk density) of the formation is an average of densities of the matrix and fluids in the pores of the mud-fluid flushed zone, and the porosity is affected by the presence of shale. The density of shale varies between 2.20 and 2.85 g/cm3, depending on the types of clay minerals in the shale.

The density log is used to estimate the effective porosity of shaley sands, assuming the shale density is approximately 2.65 g/cm3.

Nevertheless, the expression for the bulk density of a shaley, water- bearing formation is

$$\phi_{\mathrm{d}} = \left(\frac{\rho_{\mathrm{m}} + \sqrt{R_{\mathrm{w}}/R_{\mathrm{t}}}}{\rho_{\mathrm{z}} - \rho_{\mathrm{f}}} \right) - V_{\mathrm{sh}} \left(\frac{\rho_{\mathrm{m}} - \rho_{\mathrm{sh}}}{\rho_{\mathrm{m}} - \rho_{\mathrm{f}}} \right) \quad (15)$$

When hydrocarbons are present in the formation, they lower the density of the residual hydrocarbons in the mud-fluid flushed zone. The density of the hydrocarbons (and their residual saturation) must be known, alongwith the mud-fluid resistivity (R_{mf}) and the resistivity of the flushed zone (R_{xo}) that is obtained from a microlog.

E. Neutron porosity logs

The neutron-porosity log first appeared in 1940. It consisted of an isotopic source, most often plutonium-beryllium, and a single detector. Many variations were produced exploiting both thermal and epithermal neutrons. In most of the early tools, neutrons were not detected directly. Instead, the tools counted gamma rays emitted when hydrogen and chlorine capture thermal neutrons. Because hydrogen has by far the greatest effect on neutron transport, the borehole effects on such a tool are large. The now-standard compensated neutron-porosity logging (CNL) tool, in common use since the 1970s, is still a very simple tool. Like a density tool, it consists of an isotopic source (now most often americium-beryllium, although at least one tool uses an accelerator source) and two neutron detectors. The tool measures the size of the neutron cloud by characterizing the falloff of neutrons between the two detectors. Because neutrons penetrate considerably further than gamma rays, the design is much simpler than that of a density tool. It requires little collimation and does not need to be pressed against the borehole wall. The size of the fluid-filled borehole is obviously an important environmental effect that must be taken into account. As a result, even "raw" CNL porosities are reported with a borehole-size correction already applied.

1) Neutron log interpretation

Because we are stuck with values reported in apparent neutron porosity, that is how we typically interpret them. Most interpretation schemes assume that the neutron porosity is scaled in apparent limestone units; that means a limestone matrix and water-filled porosity. If the neutron matrix is not known for certain, but the actual formation matrix is, the matrix on which the neutron-porosity log was recorded can be verified by making a density-neutron cross shows a schematic example.

If the points fall along the overlay line for the actual formation matrix, the neutron log is most likely in limestone (calcite) units. If the points fall along the calcite overlay line, the log matrix is the same as the formation matrix. In particular, if the points fall along the limestone line and the reservoir is known to be sandstone, the neutron log is in sandstone units and should be transformed to limestone units before proceeding with interpretation. As the schematic shows, gas and shale can obscure these trends. [20][21][22][23]

2) Fluid effects

The hydrogen index of the pore fluid and its equivalent apparent neutron porosity can have a much bigger effect. The difference between pure water, most brines, and typical oils is small, but as the table shows, gas can have much different neutron-response properties. While the presence of gas increases the apparent porosity seen by a density log, it decreases the apparent porosity seen by the neutron log. This is the source of "gas crossover" on neutron density-log displays (see Figure 6).

Moreover, the shallow-reading density log frequently is an invaded-zone measurement, completely masking the gas effect on it. Because the neutron porosity is deeper reading, it is often the only log that can be used for gas detection. Even when not completely reading the invaded zone, the neutron-porosity log probably reads a mixture of invaded and virgin formation.

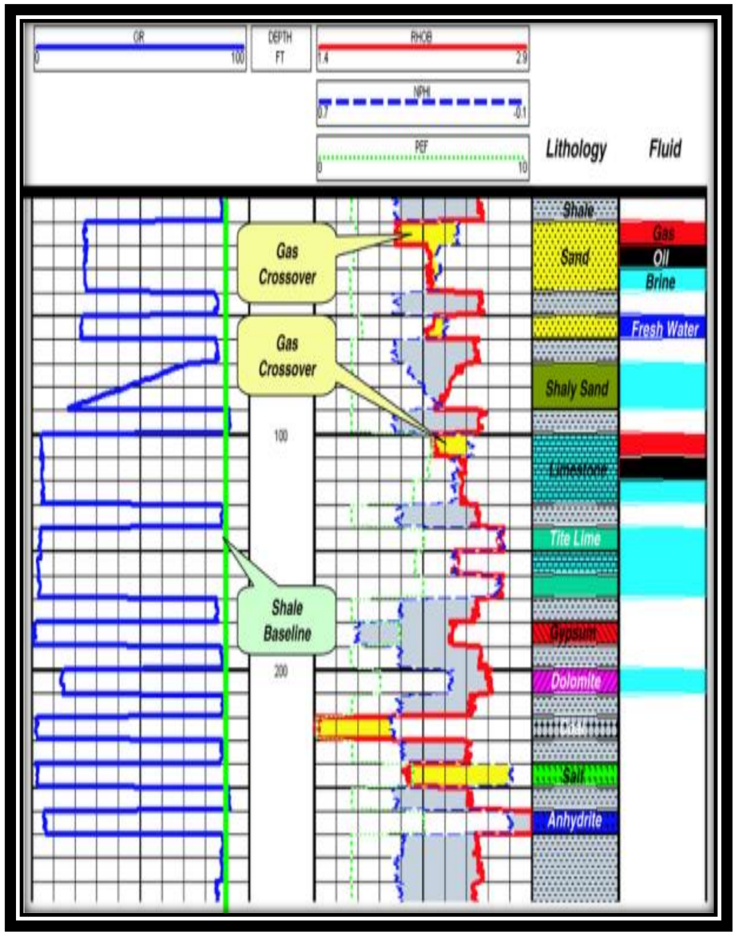

Fig.6: Schematic nuclear-log responses for some common lithologies.

V. RESULT AND DISCUSSION

A. Methods to Determine Permeability

The well logs provide detection, not evaluation, of the permeability for a zone. Some well logs and their results such as porosity logs can be used to estimate permeability by experimental correlation of log response to core permeability data and the Porosity is used larger than resistivity to evaluate the permeability. The evaluation of K from well log is very difficult because correlation between porosity and permeability may be not very accurate because the K is a measure of dynamic properties of the formation but the logs make static[24][25]

B. Resistivity Log Corrections

Apparent resistivity is measured by resistivity log. It's considered a resistivity of homogeneous medium. Apparent resistivity considers true resistivity if measurement condition be known. Before this step must be correction various kinds of resistivity log such as, LLS to LLSC, DLL to DLLC, and so on which illustrated in Figure 7. These corrections were done by IP software.

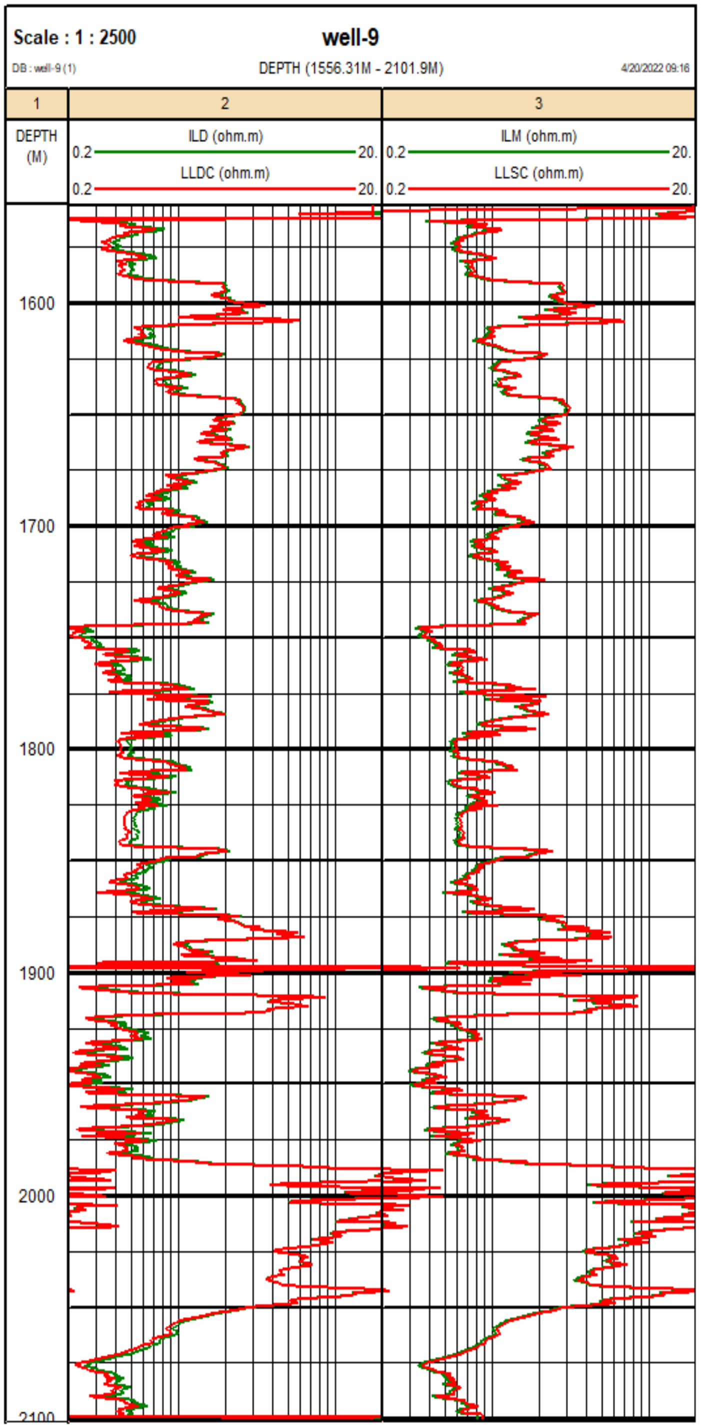

Figure7. Resistivity log corrections for (Well-9)

C. Gamma Ray Log Correction

The GR is used to identify shale beds when SP log reading curved. As well as used to evaluation and quantify radioactive minerals (Schlumberger, 2013). IP software used to environmental corrections for gamma ray log for (Well-9) shown in Figure 8.

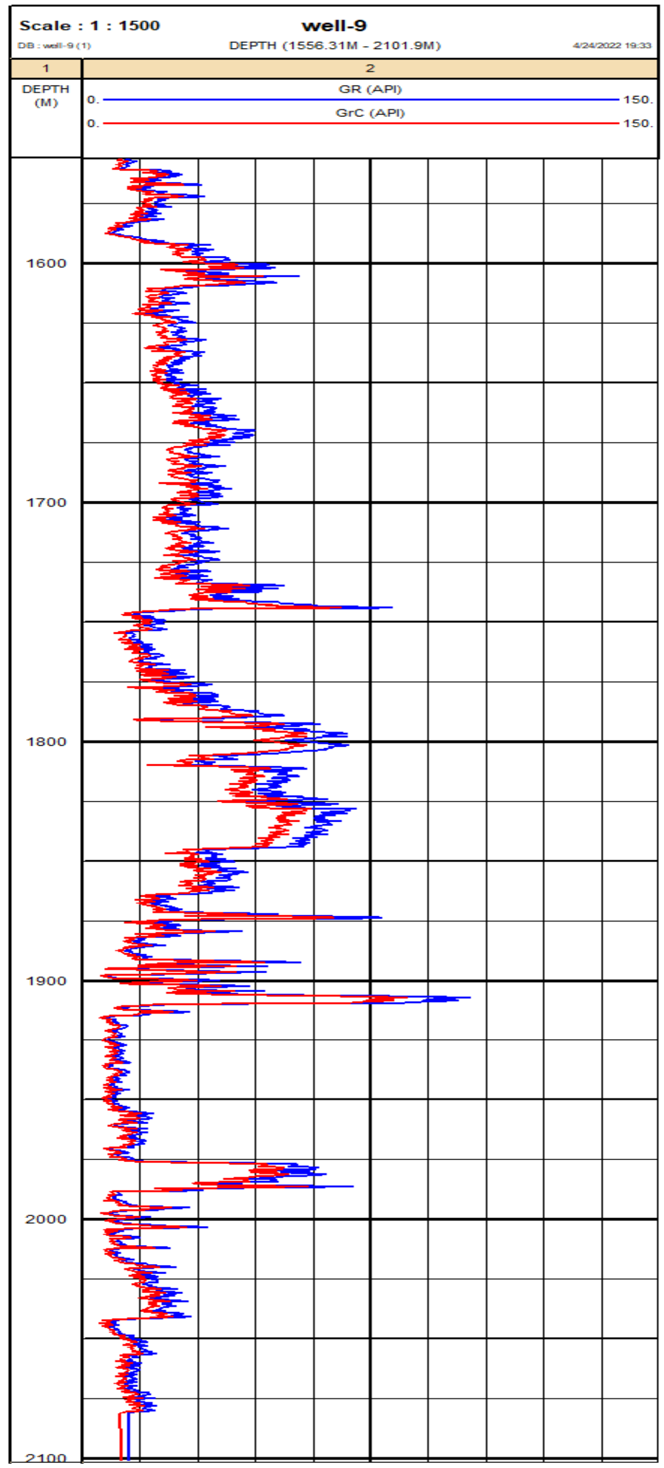

Figure 8. Gamma ray log correction for (Well-9)

D. DETERMINATION OF LITHOLOGY AND MINERLOGY

1. Neutron – density cross plot

The neutron–density cross plot is more necessary for many log interpretation procedures. Neutron and density

measurements are affected by lithology, porosity, hydrocarbon density.

Volume of clay from the cross plot between Density and Neutron logs in a very shaly formation defined by

reference to the gamma ray, first, clay point is identified and clean limestone point also identified, density for clean

limestone is usually taken 2.71.

Note the ϕD and ϕN cross plot can be used with good accuracy in oil bearing formation, the present of gas or light

oil will cause the point to shift in the north-westerly direction. In such cases Vsh should be evaluated from GR. Neutron-density cross plot, is used for detecting the lithology. The cross plots for wells show that most of points fall on the dolomite and some point fall on limestone. This indicates that Tertiary formation consists mainly from a combination matrix of limestone and dolomite. Figure (9) shows the cross plot of ϕN and ϕD with clean and clay line for well-9.[26]

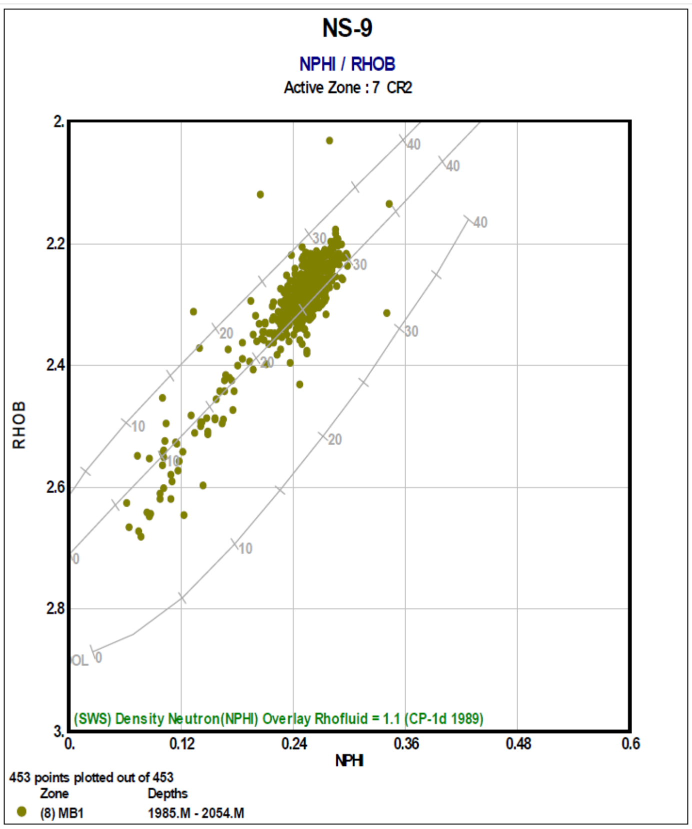

Figure 9: Neutron-density crossplot showing where the common lithologies foe (well-9).

2. The M-N Cross Plot for Mineral Identifications

The M-N cross plot generally can be used to facilities lithology interpretation and identify more complex minerals (Ross, 2015). These plots integrated of three mainly porosity logs in order to describe a particular minerals quantity by plotting M and N values in the chart. The M and N values are slopes of individual minerals, calcite, dolomite, sandstone, Gypsum, sulfur, gas and secondary porosity area on the sonic-density and density-neutron cross plot charts in Fig. 10. M and N are introduced by following equations.

$$M = \frac{\Delta tfl - \Delta tlog}{\rho b - \rho fl} \times 0.01 \qquad (16)$$

$$N = \frac{\Phi Nfl - \Phi N}{\rho b - \rho fl} \qquad (17)$$

The M-N cross plot for tertiary reservoir shows that points focused between lines calcite and dolomite with observed tendency approach to secondary porosity area that illustrated in Figure 11 for well-9.[27]

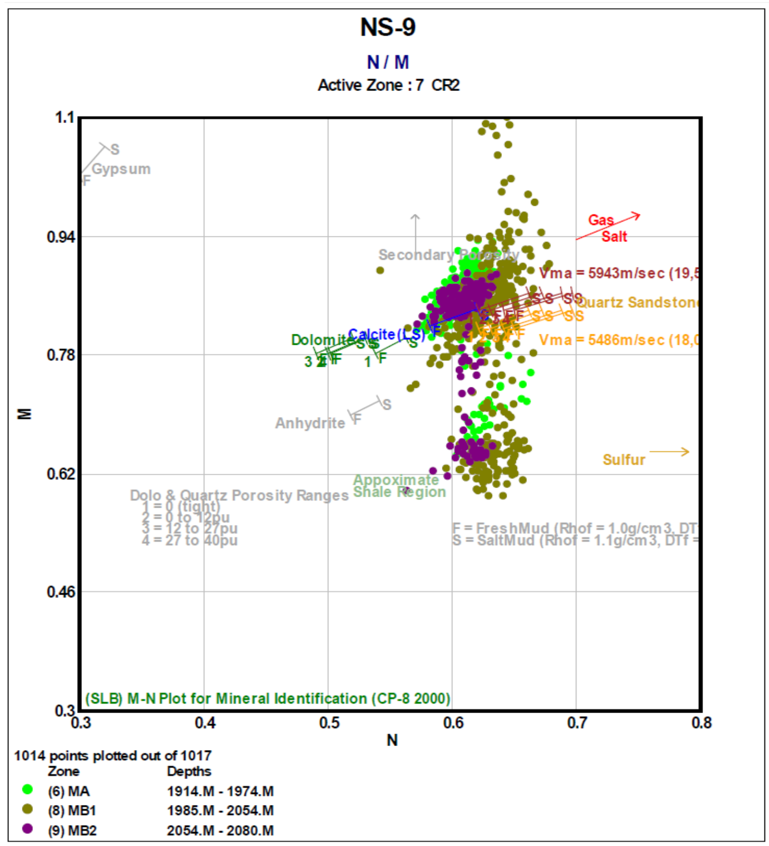

Figure. 10: The M-N Cross Plot for Mineral Identifications foe (well-9).

E. Calculation of Porosity

Density and neutron must be corrected in order to obtain more accurate for calculations porosity determination shown in Fig. 11. Corrections have been applied by using the following equations For density porosity log applying the following equations (Schlumberger, 1997)[28]:-

$$\emptyset D\ correc. = \emptyset d - (Vsh \times \emptyset Dsh) \quad (18)$$

For neutron porosity log applying the following equations (Debrandes, 1985)[29] :-

$$\emptyset N\ correc. = \emptyset n - (Vsh \times \emptyset Nsh) \quad (19)$$

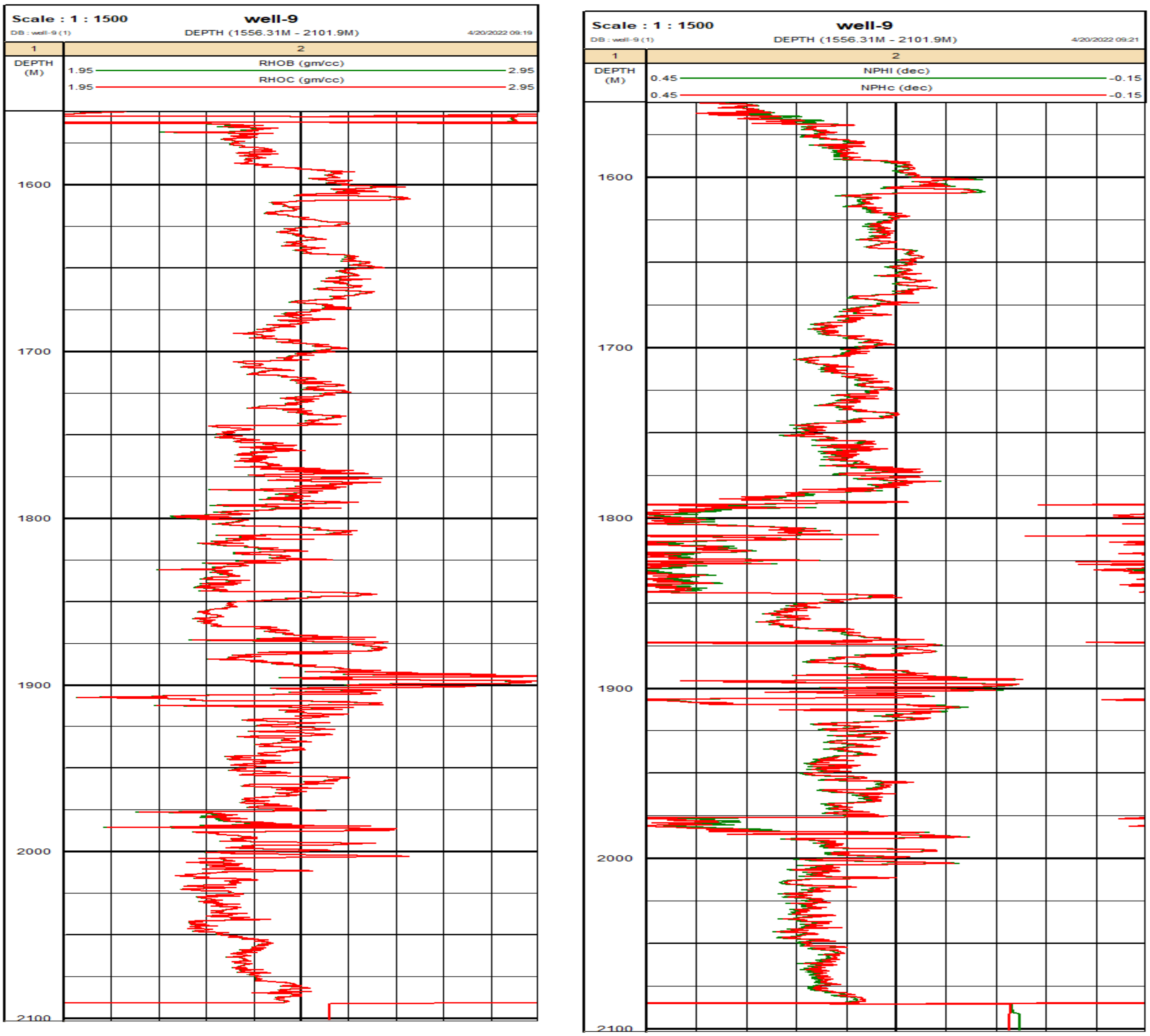

Figure 11: Neutron and density logs corrections

F. Clay Volume

Volume of clay (Vcl) is the most critical parameter to determine in shaly sand analysis. Yet in many areas it is very difficult to determine volume of clay accurately. An overestimation of clay volume can result in effective water saturations (Swe) that are too low, thus making the reservoir look productive. Under-estimation of clay volume can result in effective water saturations that are too high, which can result in the bypassing of a productive zone. The underestimation and overestimation of volume of clay will also affect the calculation of effective porosities used to determine both effective water saturations and net pay. As shown in the figure (12).

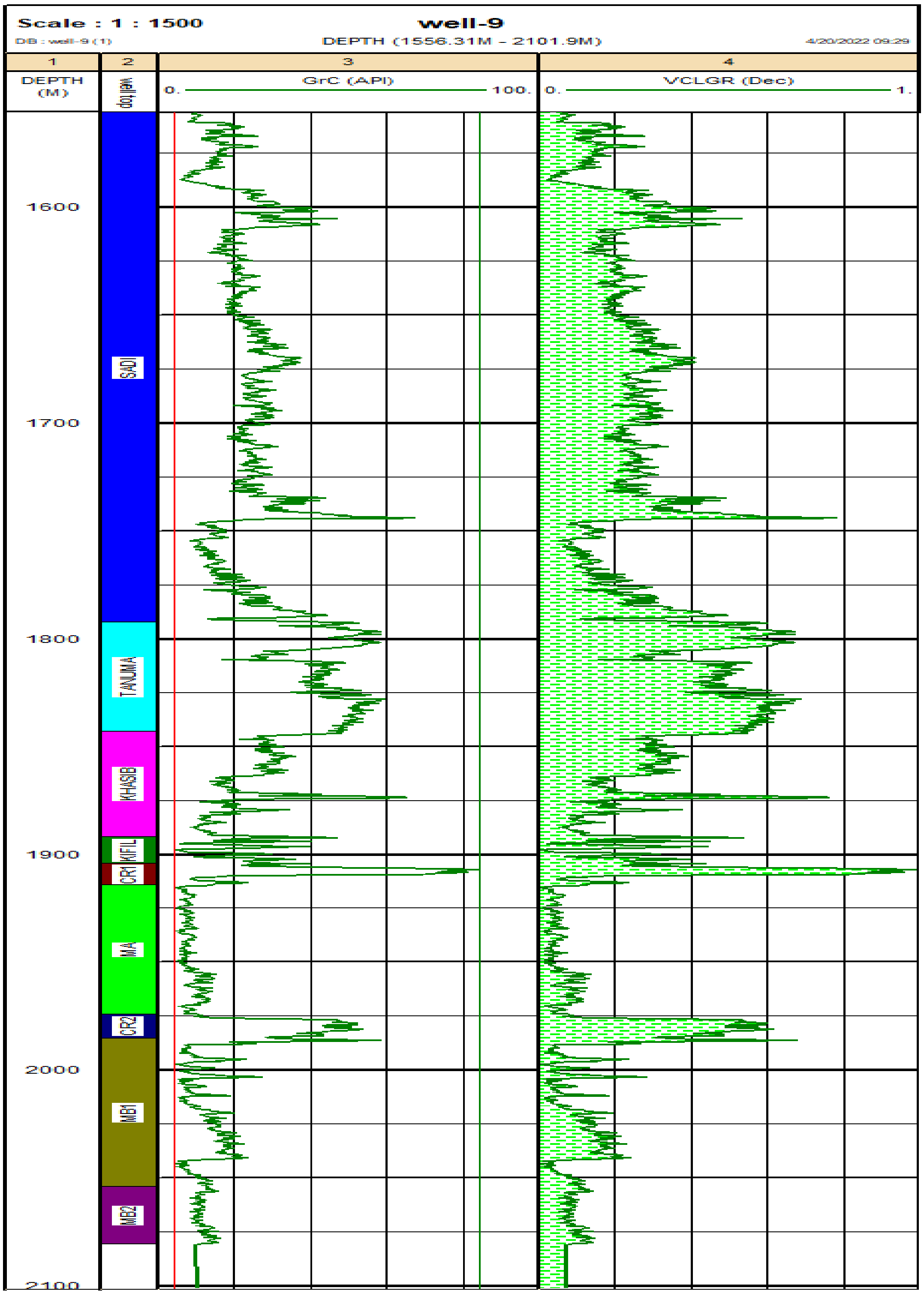

Figure (12) the clay volume for (well-9)

G. Net to Gross reservoir calculation

Net pay is important parameter in reservoir calculation because it's used to identify geological section which penetrated formation and identify interval of reservoir which have amount of hydrocarbon is a function of production interval. Determination the net pay requires three important values. These values are, porosity, water saturation, and permeability to nreservoir fluids.Net-gross ratio is a function of the quality of the limestone as potential reservoirs in Mishrif Formation. Net pay is quantified value which can be used in Cutoff evaluation are performed to log interpretation data shown in Figure (13).

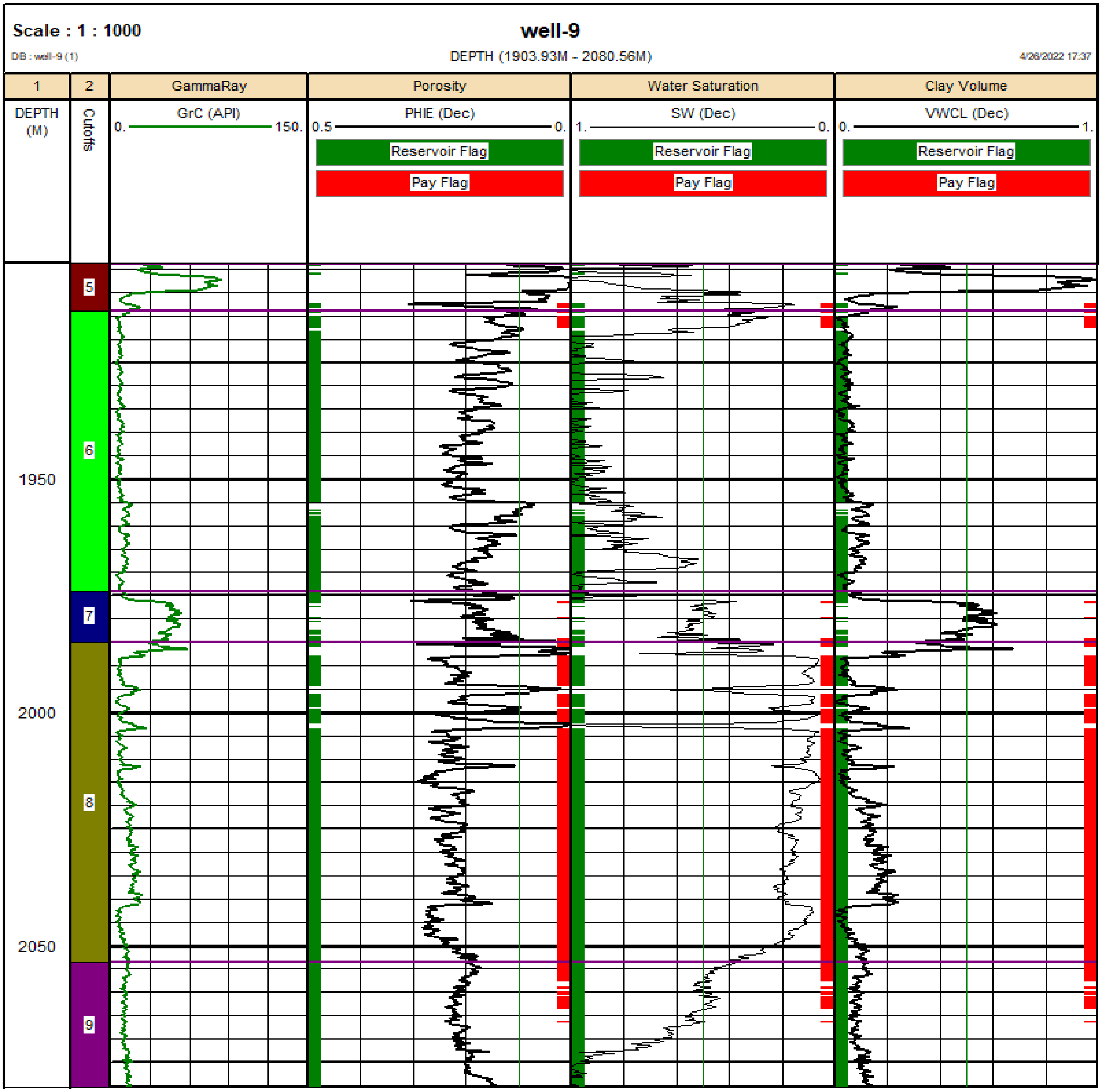

Figure 13. Net to Gross in (well-9)

H. Computer processes interpretation

These processes are valuable in order to Petrophysical analysis easier. These processes were used for; 1) Division the units of Formation into reservoirs and non-reservoirs (cap rocks); 2) comparison of the reservoir's units according to the Petrophysical properties for each unit. Finally, these processes represent the last step in terms of petrophysical properties. Figures (14).

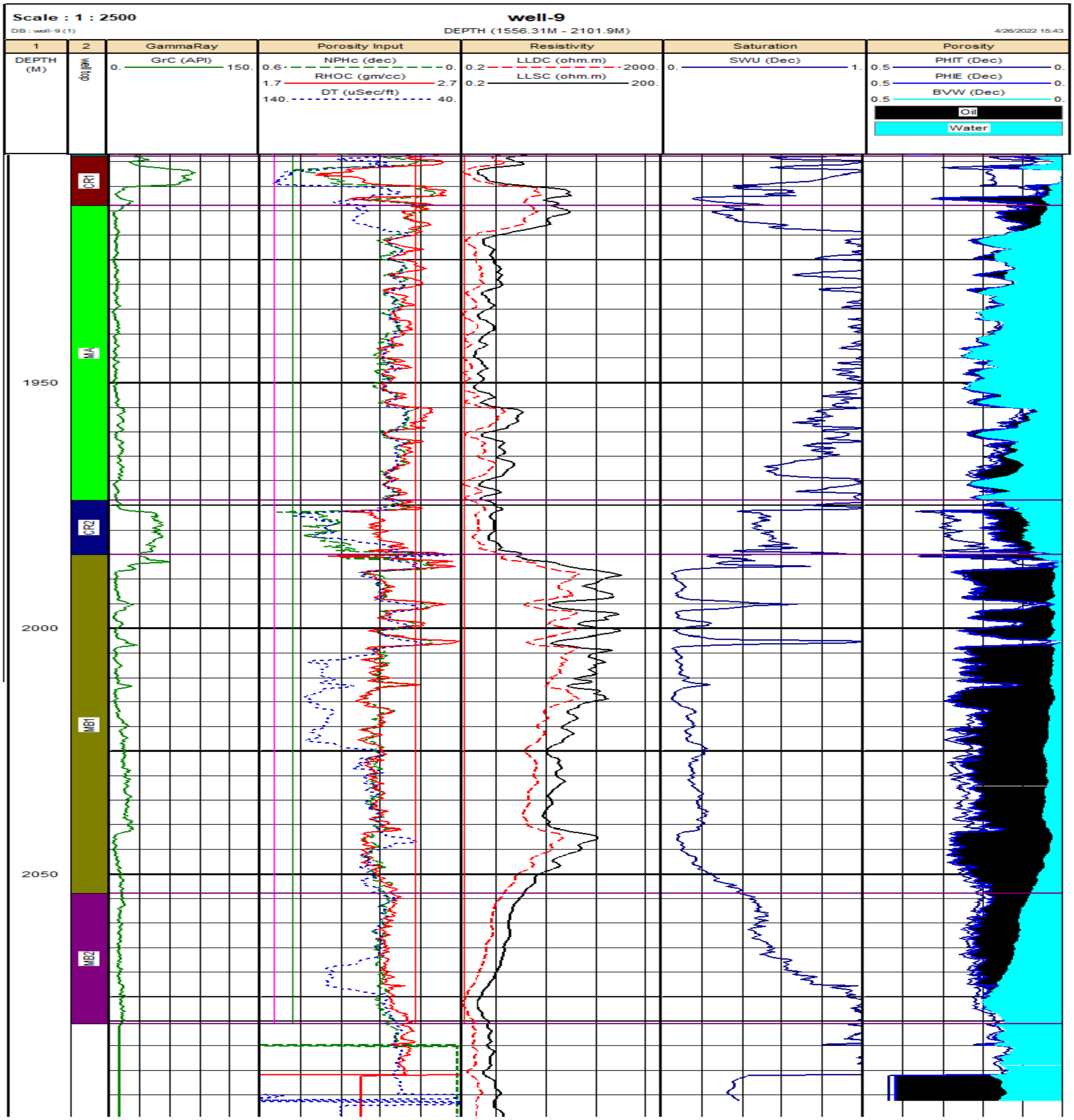

Figure 14-CPI Computer processes interpretation (well-9)

VI. CONCLUSION

The study aimed to characterize the reservoir in Nassiriya oil field and calculate the petrophysical properties (shale volume, total and effective porosity, and water saturation) using well logs data sets by using IP software. It can be concluded that:

– The Mishrif Formation consists of two main units separated by a shale layer, the upper unit has low reservoir properties, and the lower unit has good reservoir properties.

– Based on the petrophysical properties variation with depth, the Mishrif Formation in the Nasiriya Field is divided into four units.

– The unit Mishrif mB1 is the best unit in Nasiriya field that characterized by the higher reservoir properties and represent the principle oil-bearing zone.

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VIII. CERTIFIED BOOKS

- Reservoir Engineering HandBook TAREK AHMED.
- HandBook Schlumberger

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