

Chapter 5

Petrophysical Modelling of Carbonate Reservoir from Bombay Offshore Basin



Monesh Sharma, Kumar Hemant Singh, Sanjay Pandit, Anil Kumar and Ashok Soni

Abstract The integration of well logs with laboratory measurements derived from core to analyse the reservoir characteristics of WELL P, of Bombay Offshore Basin, India. The reservoir properties such as permeability (k), Porosity (ϕ), shale volume (V_{sh}), lithology, water saturation (S_w), net pay thickness and other parameters were determined from well logs. The petrophysical model was derived from depth X150 m to X400 m. But the main focus of analysis were four pay zones named as Zone A (X195 m to X212 m), Zone B (X226 m to X282 m), Zone C (X299 m to X310 m) and Zone D (X338 m to X374 m). The logs used for analysis were CGR, NPHI, RHOB, LLD, DTCO and DTSM. Fluid types were identified by NPHI versus RHOB crossplot, VP, VS (vp/vs) versus DTCO crossplot and neutron/density log signatures which indicate the absence of gas and the presence of oil and water in the given well. The signatures of DTCO and DTSM followed each other indicating the absence of gas in the pay zones. Wet resistivity quick look technique was applied to locate the hydrocarbon-bearing zones of interest and any crossovers on density and neutron logs as indicators of the presence of oil zones. Saturation cross plots (Pickett plot) was used to determine the saturation exponent (n), cementation factor (m), tortuosity factor (a), and formation water resistivity (R_w), a prerequisite to their use in the determination of water saturation from Archie's equation. The main lithology in the region of the study was limestone (calcite) and shale (illite). Shale although present but was in a very small amount. The final volume fractions obtained of each mineral mainly calcite and dolomite from the petrophysical model were compared with those obtained from X-ray Diffraction (XRD). The average porosities of four zones were found to vary from 14.1 to 16.9% which indicated good porosity for a carbonate reservoir. The average water saturations of zones varied from 0.631 to 0.667. The results of the study indicate that the zones where the porosity is good, the measured permeability turns out to be poor (less than 5 mD) which suggests that the pores perhaps are not interconnected. This could be true for carbonates. Thus, the measured values need to be compared with the porosity and permeability values

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obtained from other laboratory measurements like Routine Core Analysis (RCA) and MicroCT scan to study the connectedness and non-connectedness of the pore-system in the cores.

Keywords Petrophysical model · Well logs · RCA · XRD

1 Introduction

Carbonates hold up to 60% of the world's hydrocarbon reserves and hence plays a major role in fulfilling the hydrocarbon demand of the coming generations. However, carbonates display strong heterogeneity in terms of porosity distribution and their permeability primarily due to the post-depositional processes like dissolution, recrystallization, precipitation, collectively known as diagenesis, which affects and alter the properties of the carbonate reservoirs entirely (Ahr 2008).

Porosity is defined as the ratio of pore volume to the total volume in a given rock sample. However, the porosity in Carbonates is completely in contrast to clastics (except in some cases). The genesis of the carbonate porosity lies in 'post-depositional chemical dissolution', and as a result the secondary porosity takes dominance (Akbar 2001) in the form of fracturing or dissolution channels or vugs. Normally the carbonate is made up of two items: (a) Finer grained matrix material which is very fine, sub-crystalline texture and interstitial material called Micrite. They could also be found as fine textured, coarsely crystalline called Sparite. (b) Allochems are Fossils, Molds, Oolites or Intraclasts.

One of the major challenges of petrophysical evaluation of carbonate reservoirs is to estimate important properties of reservoirs such as porosity, permeability, water and hydrocarbon saturations and mineralogy as accurately as possible. Unlike sandstone with well-established porosity, permeability, saturation, etc. the heterogeneous pore-system of carbonates defy routine petrophysical analysis since most of the relationships were developed for the clastic depositional environment (Lucia 1995; Marzouk et al. 1995).

An accurate prediction of the petrophysical parameters can be achieved by using log data along with the integration of core data obtained from the same well. The paper presents the preliminary results from Well P of the Bombay offshore region for all pay zones as inferred from the log data and Well Completion Report. The X-ray Diffraction (XRD) experiments and Routine Core Analysis (RCA) were performed on core samples to identify minerals present in the core samples which is then used to constrain the petrophysical models derived from log data analysis.

2 The Study Area

2.1 Geology and Stratigraphy

The Bombay offshore basin is a divergent passive continental margin basin which is situated on the continental shelf off the west coast of India. The basin is confined to the bounds of the western coastline of India, Bombay Offshore is a pericratonic rift basin located on the western continental shelf of India (USGS 2000). In the North-west, it is bounded by Saurashtra peninsula, north by Diu arch, East by Indian craton and south by Vengurla arch which divides the Mumbai offshore with Kerala-Konkan basin. There are five structural provinces viz. Surat Depression in the north, Panna-Bassein-Heera Block in the east-central part, Ratnagiri in the southern part, Mumbai High-/Platform-Deep Continental Shelf (DCS) in the mid-west and Shelf Margin adjoining DCS and the Ratnagiri Shelf.

According to the DGH (2019), this is a category-I basin which has a proven commercial productivity and it covers an area $\sim 116,000 \text{ km}^2$ for up to 200 m bathymetry. Bombay high field in the western offshore region of India is a giant carbonate field. The field was discovered in 1974 by Indian National Oil Company ONGC is producing since 1976 and now is in its mature phase. The field covers an area of 1200 km^2 with over 600 drilled well. The field produces from Miocene L-III limestone reservoir. It has around 10 separate hydrocarbon-bearing layers with very less vertical communication. The current study is from one such reservoir in a well of one such field in Bombay offshore basin in western offshore of India.

2.2 Well Log and Core Data

In our study area, Bombay High-DCS and Ratnagiri Block of Mumbai Offshore Basin has reservoir rock of carbonates of Lower Miocene period. The logs used for analysis were CGR, NPHI, RHOB, LLD, DTCO and DTSM. Core samples from carbonates were made available for research work in the laboratory (Fig. 1). The aim of this work is to integrate the laboratory measurements like RCA and XRD with traditional logs to derive the most accurate estimates of the petrophysical parameters of the reservoir (for instance lithology, hydrocarbon volume in place, porosity, water saturation, and permeability).

Data from one well (Well P) was made available for the study with a suite of logs, including caliper, spontaneous potential (SP), gamma-ray (GR), density (RHOB), neutron and density porosity (PHIN and PHID), PEF and shallow and deep resistivity (LLD, LLS) (Fig. 1). P- and S-wave sonic logs are also available for detailed analysis. The well is located in the South-West region of the Bombay Offshore Basin. The mentioned suite of well logs is used in evaluating petrophysical properties such as Porosity (ϕ), Hydrocarbon saturation (S_h), Water Saturation (S_w), Permeability



Fig. 1 Core samples for Well P collected from Regional Geological Laboratory, Panvel, Maharashtra, India

and Water Resistivity (R_w) and hence the Hydrocarbon potential of the region can be assessed.

2.3 *Petrophysical Modelling*

The log analysis begins with the identification of the zones of interest and demarcate the clean and shale baselines on the logs. Certain quick look methods such as density and neutron porosity crossover, wet resistivity method can be used which provide indicators that point to certain hydrocarbon zones requiring further investigation (Tiab and Donaldson 1996; Schlumberger 2008).

2.3.1 **Lithology Determination**

Lithology is best determined using Neutron-Density crossplot. The natural radiation of the formation is measured through Gamma log which are indicative of litho units in the subsurface in the vicinity of wells. On the crossplot, the clustering of data can be studied on the lithology line. This could indicate the dominant lithology present

in the area. The crossplots between Vp/Vs and DTCO could also be used to identify the lithology. These crossplots are also routinely used to identify the gas zones and shale zones (Mheluka and Mulibo 2018).

2.3.2 Wet Resistivity (Ro) Quick Look Technique

The quick look technique is applied to identify the hydrocarbon-bearing zones. In this method, Ro from the porosity and an estimate of formation water resistivity (R_w) is calculated. Ro is then plotted as an overlay on the deep resistivity curve. In water-bearing zones, Ro and the deep resistivity should overlay seamlessly while in hydrocarbon-bearing zones, the deep resistivity should be higher than Ro, with the separation increasing with increasing hydrocarbon saturation. The basic formulation of the technique is (Archie 1952):

$$R_o = F \times R_w = (a \times R_w) / \phi^m \quad (1)$$

where Ro is the resistivity of the formation saturated with water, R_w is the Formation water resistivity, ϕ is the Porosity, and a is the tortuosity factor.

2.3.3 Shale Volume Estimation Using Gamma-Ray Log

The volume of shale can be estimated using non-linear and linear equation functions. A linear response is used because age information of lithounits is generally unavailable. The non-linear responses have been formulated by Steiber, Larionov (for older strata), Larionov (Tertiary) and Clavier. This method does not work well in areas where radioactivity is not primarily associated with the clays, such as in feldspathic sands. Linear Scaling method is used in this study for estimation of the volume of shale.

The volume of shale and Gamma-ray index are related as:

$$V_{sh} = I_{GR} = (GR_{log} - GR_{min})(GR_{max} - GR_{min}) \quad (2)$$

where V_{sh} is the shale volume fraction calculated using the GR_{log} response, I_{GR} is the gamma-ray index, GR_{min} is the minimum gamma-ray from the log, GR_{log} is the gamma-ray reading from the log, and GR_{max} denotes the maximum gamma-ray from the log.

2.3.4 Porosity Estimation

The estimation of porosity is done using density and neutron logs. Porosity parameter is determined from the density logs by taking the bulk density readings obtained from the formation density log within each reservoir and then applying the value to Eq. (3)

for calculating the porosity. The porosity can be calculated from the density log as follows:

$$\varnothing_D = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_f) \quad (3)$$

where \varnothing_D is the porosity calculated through the density log, ρ_{ma} is the matrix density, ρ_b is the bulk density as obtained from the log and ρ_f is the fluid density. The total porosity is the average of the two measurements obtained from Density (\varnothing_D) and Neutron (\varnothing_N):

$$\varnothing_T = (\varnothing_D + \varnothing_N) / 2 \quad (4)$$

The effective porosity \varnothing_E is the actual porosity needed in determining water saturation and reserve estimation. The effective porosity is determined from the total porosity (\varnothing_T) after eliminating the effect of shale using the following relationship:

$$\varnothing_E = \varnothing_T (1 - V_{sh}) \quad (5)$$

2.3.5 Saturation Crossplot (Pickett Plot)

The water-bearing zones are equally important as hydrocarbon-bearing zones, hence they both need to be determined. The Pickett plot is one such technique which is used for their estimation. The Pickett plot provides information about the parameters Archie's constants like a , m , n and R_w which is crucial for determining the water saturation from Archie's equation.

$$\log(\phi) = -\frac{1}{m} \log(R_t) + \frac{1}{m} (\log(ax R_w) - n \log(S_w)) \quad (6)$$

2.3.6 Water Saturation Estimation

After calculating the effective porosity, water saturation is determined from Archie's equation. The Archie equation for calculating water saturation in clean, porous rocks is given by:

$$S_w^n = \frac{a R_w}{\phi^m \times R_t} \quad (7)$$

$$S_h = 1 - S_w \quad (8)$$

where R_f is the Formation Resistivity, S_w is the water Saturation, ϕ is the Total Porosity, m is the cementation exponent, a is the Tortuosity Factor, R_w is the Water Resistivity and R_{sh} is the Resistivity of Pure Shale.

2.3.7 Permeability Estimation

Permeability is a measure of the ability of a porous media to transmit fluid (Tiab and Donaldson 1996). Permeability can be computed from empirical models like Wylie and Rose (Eqs. 9 and 10), Timur (Eq. 11) based on grain size, pore dimensions, mineralogy and surface area, or water saturation. The details of these methods can be found in Tiab and Donaldson (1996). Typically, the log derived permeabilities are valid only for estimating permeability in formations at irreducible water saturation. So before using the equations for determining permeability, whether the formation is at irreducible water saturation or not, must be determined.

$$K = \left(250 \times \frac{\phi^3}{S_{wirr}} \right)^2 \quad (9)$$

$$K = \left(79 \times \frac{\phi^3}{S_{wirr}} \right)^2 \quad (10)$$

$$K = \left(93 \times \frac{\phi^{2.2}}{S_{wirr}} \right)^2 \quad (11)$$

where K is permeability, ϕ is porosity and S_{wirr} is irreducible water saturation.

2.3.8 Core Sample Analysis

Core data can be used as a reference to study the parameters interpreted with wireline logs. Routine Core Analysis data points can be plotted on the log analysis depth plots for comparison. The volume fraction of minerals obtained from petrophysical models can be compared with those obtained from the XRD analysis for available for cores at respective depths. The XRD data points can also be plotted on the log analysis depth plots for comparison.

2.3.9 Net Pay

The porosity cut-off of 5% was used for the analysis while shale volume cut-off of 50% was defined for the quality of the reservoir rock. Water saturation, S_w , cut-off value of 70% was used to define pay. The reservoirs were defined by the porosity greater than 5% and less than 40% and shale volume less than 50%. For the net pay, if

the water saturation within the reservoir is less than 70%, it is considered to contain hydrocarbon.

2.3.10 Quanti-Elan

The petrophysical was created using the Quanti-Elan module of Techlog software provided by Schlumberger. The module follows the principle of inversion of the data. Linear equations in Quanti-Elan has a general form as:

$$L_1 = C_{11}V_1 + C_{12}V_2 + \dots + C_{1n}V_n, \quad (12)$$

where V_n 's are the volumetric components and C_n 's are endpoints values for L_n equation at 100% of n component in the rock. A response equation is a mathematical description of how a given measurement varies with respect to each formation component. The simplest linear response equation can be expressed as:

$$\text{measurement} = \sum_{i=1}^{\text{fc}} V_i \times R_i \quad (13)$$

where, V_i is the volume of formation component i , R_i is the response parameter for i th formation component fc. Although some linear equations include additional terms, and the non-linear equations are more complex, the concept displayed by Eq. (12) remains the same. Hence, the total measurement observed is determined by the volume of each formation component and how the tool reacts to that formation component?

3 Results

The methodology described above is basically applied to create a Petrophysical model from X150 m to X400 m. There are four zones of interest in the WELL P which are described as pay zones A to D (reservoir zones) (Fig. 2). The depths ranges of pay zones are mentioned in Table 1.

3.1 Lithology Determination and Gas Indication Using

NPHI versus RHOB Crossplot

The crossplot calculated for NPHI versus RHOB is shown in Fig. 3. The depth between X150 m to X400 m shows most of the data points to cluster along the limestone and dolomite lines. The data points away from the dolomite line indicate

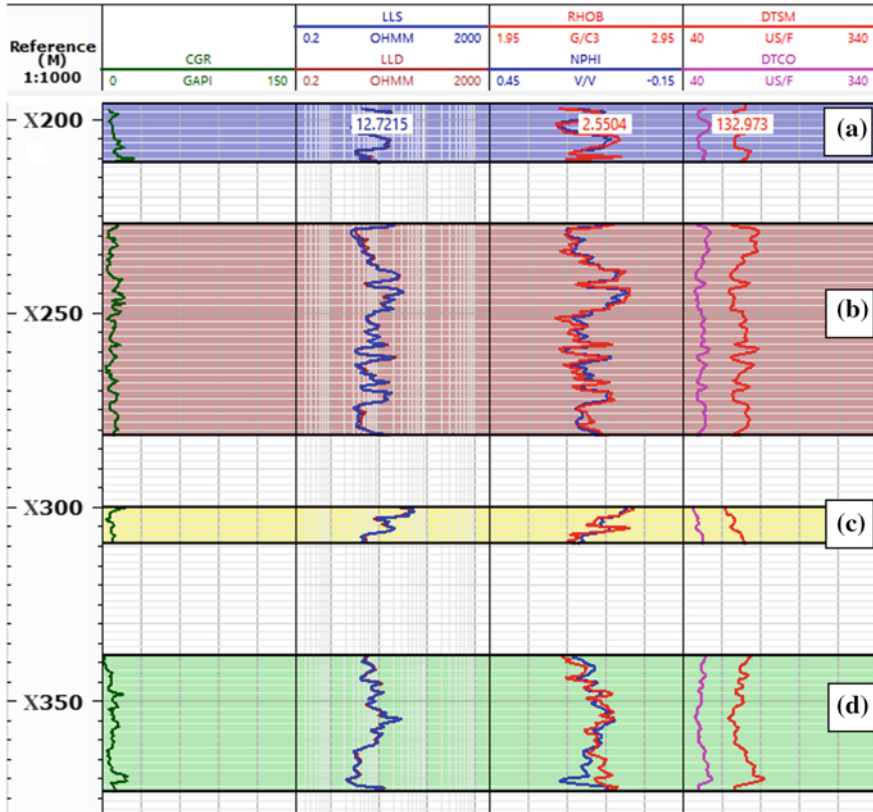


Fig. 2 Depth ranges of pay zones (A–D) highlighted on well log data of Well P

Table 1 Depth range of pay zones (A–D) in Well P

Pay zone	Top (m)	Bottom (m)
Zone A	X195	X212
Zone B	X226	X282
Zone C	X299	X310
Zone D	X338	X374

shale zones. There are no points towards low bulk density values which indicate that there are no gas zones present in the given data. Thus the dominant lithology in the reservoir is limestone.

Vp/Vs versus DTCO crossplot

The result highlighted in Fig. 3 is also confirmed from the V_p/V_s versus DTCO crossplot. If gas is present in the formation the compressional wave becomes slower, while the shear wave is not affected. The V_p/V_s versus DTCO in gas sand will, therefore, be different from a water-saturated sand. Thus, if DTCO becomes slower

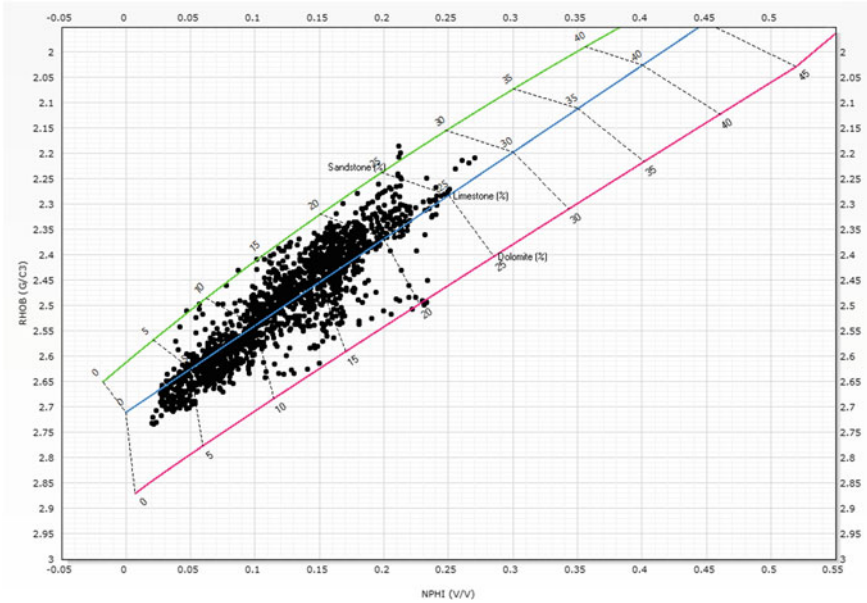


Fig. 3 NPHI (Y-axis) versus RHOB (X-axis) crossplot for WELL P from depths X150 m to X400 m

while shear stays constant (thus a lower VP/VS) then this can be interpreted as a qualitative indication that gas is present. It is only an indication of gas (or light oil), but it does not help quantify the exact amount of gas present. All the lines on the plot are theoretical lines based research on a few data sets, and not all formations follow the standard. Figure 4 shows most data points to cluster on the limestone line indicating that the prominent lithology is limestone and shale.

Saturation Crossplot

The Pickett plot shown in Fig. 5 provides the relationship between the porosity values and resistivity for the entire depth range of the reservoir for all four zones. The estimated values are $a = 1$, $m = n = 2$ and R_w to be $0.11 \Omega m$.

3.2 Depth of Interests from Wet Resistivity Quick Look Method

To illustrate the methodology, zone B is shown in Fig. 6 for the depth range X226 m to X282 m. At depths where LLD (Deep resistivity) exceeds R_o (Resistivity of formation water), the presence of hydrocarbon is indicated and is confirmed from the crossovers seen in RHOB and NPHI curves for corresponding depths.

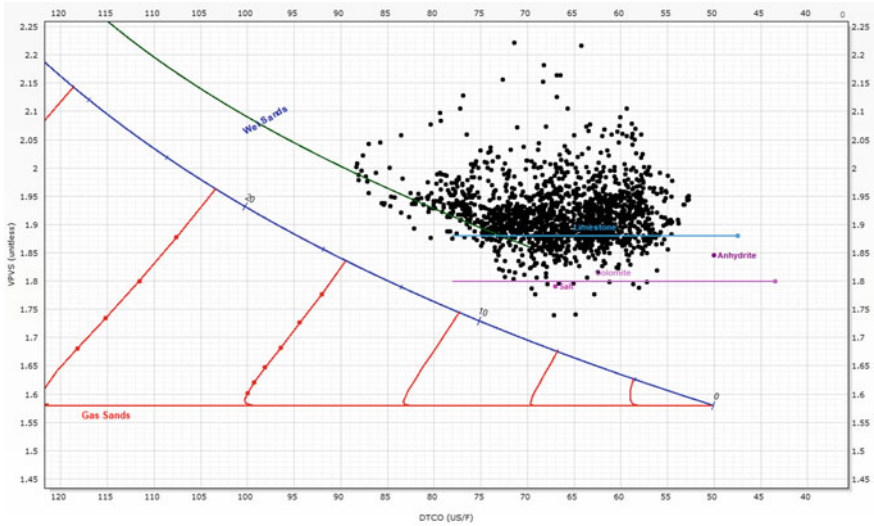


Fig. 4 Vp/Vs (Y-axis) versus DTCO (X-axis) crossplot for WELL P from depths X150 m to X400 m

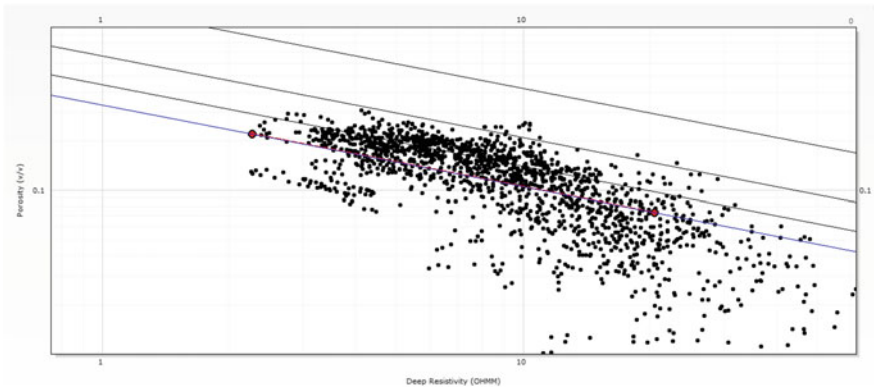


Fig. 5 Pickett plot of Porosity (Y-axis) versus Deep Resistivity (LLD) (X-axis) crossplot for WELL P from depths X150 m to X400 m

3.3 Petrophysical Model

4 Summary and Conclusions

The petrophysical well logs were used to derive petrophysical properties for the hydrocarbon-bearing zones. The resultant properties were then calibrated using the RCA and XRD from the core samples. The result of calibration can be summarised as follows (Figs. 7 and 8)

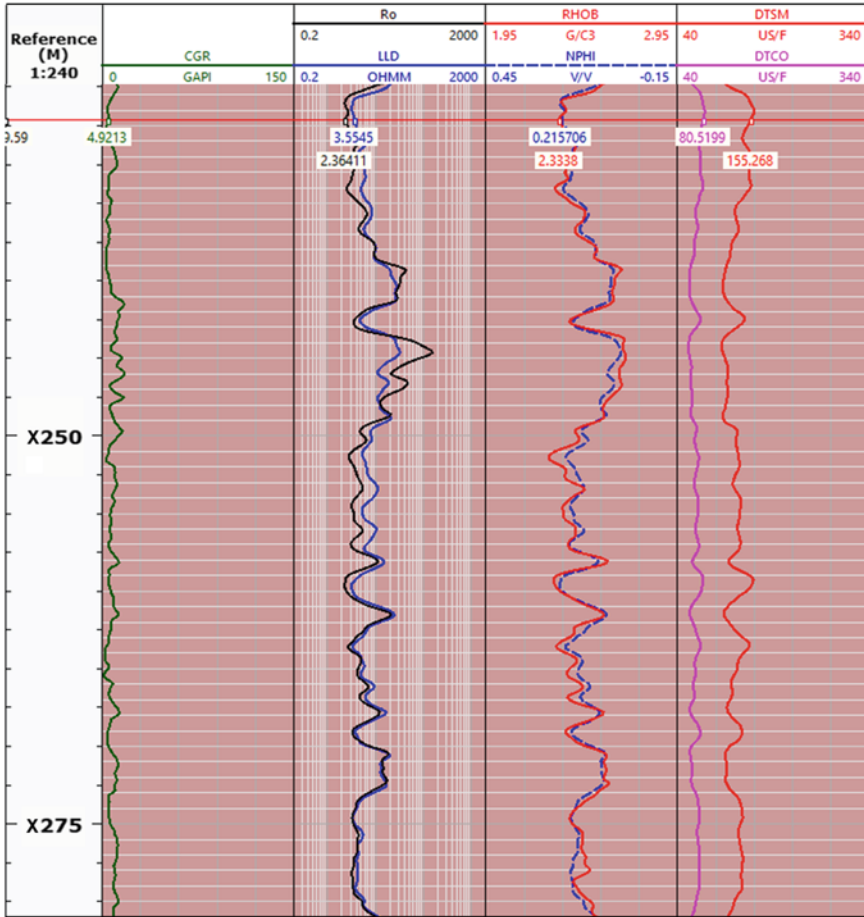


Fig. 6 Quick look Technique has shown for WELL P shown for zone B in the second track

1. The calculated petrophysical properties such as dry mineral volume fractions from well logs agree well with the volume fractions obtained from XRD.
2. The grain density and porosity calculated from well logs matches well with the grain density and porosity obtained from core samples.
3. The above properties obtained from well logs matches well with the core equivalent with the margin of error in the estimation of depth for core samples.

The resultant petrophysical properties such as average porosity, average saturation and average shale volume along with Net Pay and Net to Gross ratio has been presented in Table 2. The lithology is mainly calcite dominated with a small fraction of dolomite at a few intervals. The shale volume in the studied zone is negligible. The average porosity in the analysed zones is from 14 to 17% with an oil saturation

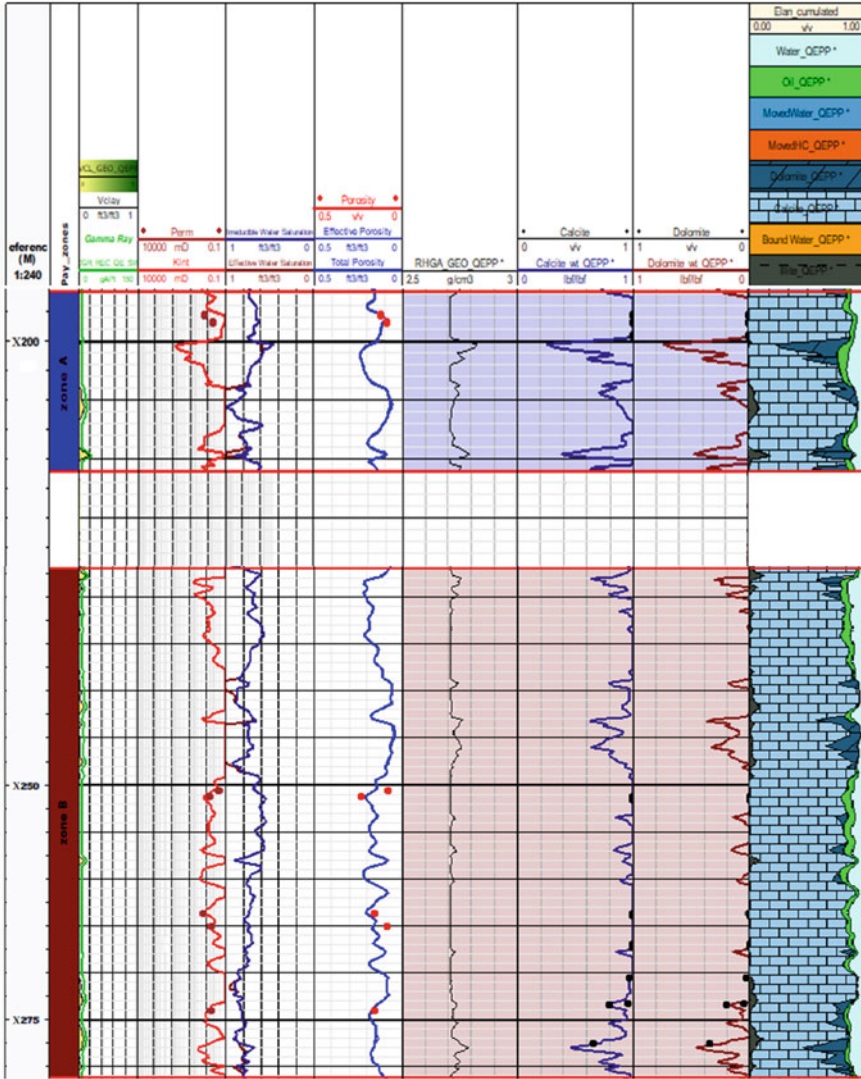


Fig. 7 Final Petrophysical Model for WELL P (from depth X195 m to X282 m). The shaded portions are Zone A and B. From left shale volume (first track), permeability (second track), water saturation (third track), porosity (fourth track), calcite volume fraction (fifth track), dolomite volume fraction (sixth track). Points in the second (permeability) and fourth (porosity) track indicate core data whereas in fifth (calcite volume fraction) and sixth (dolomite volume fraction) indicate XRD data

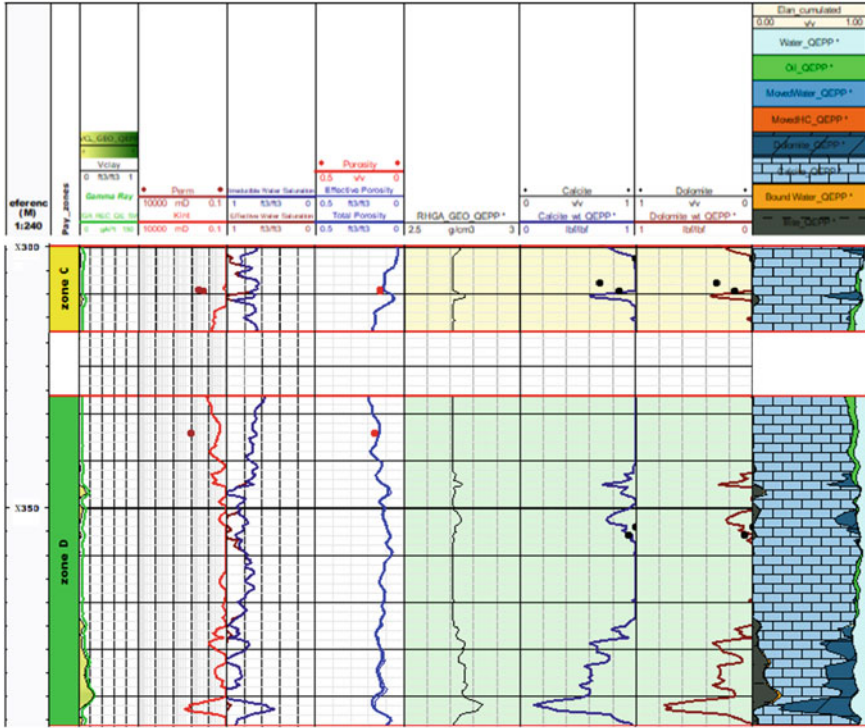


Fig. 8 Final petrophysical model for WELL P (from depth X299 m to X374 m). Zone C and D are highlighted

Table 2 Petrophysical model of Well P for all pay zones

Pay zone	Top (m)	Bottom (m)	Net/Gross (frac-tion)	Net pay (m)	Gross (m)	Avg. Por.	Avg. Sat (S_w)	Avg. Shale Volume
Zone A	X195	X212	0.388	5.893	15.187	0.161	0.649	0.026
Zone B	X226	X282	0.295	16.002	54.292	0.169	0.631	0.011
Zone C	X299	X310	0.283	2.602	9.208	0.141	0.667	0.000
Zone D	X338	X374	0.134	4.724	35.190	0.158	0.650	0.006

of ~35%. The permeability obtained from RCA suggests that the above zones have 1–10 mD.

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