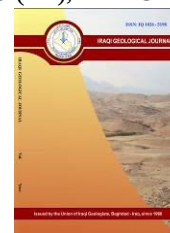




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Petrophysical and IPSOM Electrofacies Characterization of the Hartha Formation in Xn Oil Field, Central Iraq

Ayat Diffaa^{1*}, Amer A. Al-Khalidy¹ and Ali Aji²

¹ Department of Applied Geology, College of Science, University of Babylon, Babylon, Iraq

² Department of Geology, College of Science, University of Damascus, Damascus, Syria

* Correspondence: sci618.ayat.a@student.uobabylon.edu.iq

Abstract

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Carbonate reservoirs of the Hartha Formation in central Iraq are characterized by significant heterogeneity, which poses challenges for accurate petrophysical evaluation. Traditional interpretation approaches often fail to adequately capture vertical and lateral variability in carbonate systems. The study presents a combination of conventional log interpretation and Interactive Petrophysics Self-organising Maps-based electrofacies classification to improve reservoir characterization and identify productive intervals. Wireline logs from wells EB-4, EB-52, and EBSZ-1 were subjected to quality control through depth matching, core-log calibration, and neutron-density crossplots. Petrophysical parameters were estimated using a carbonate workflow calibrated to core and SCAL data, with water saturation calculated using the Archie equation. Interactive Petrophysics Self-organising Maps electrofacies classification enabled effective reservoir zonation and differentiation between high and low quality intervals. The Hartha Formation shows strong vertical heterogeneity, with Ha-2 representing a low-quality water-bearing unit, while Ha3, particularly Ha3-c, forms the main reservoir unit with better porosity and lower water saturation. Net pay varies across the field, with EB-4 showing the highest values.

Keywords: Techlog; Hartha Formation; IPSOM; Hydrocarbon Saturation; Cutoff; Net pay

1. Introduction

Carbonate reservoirs are inherently heterogeneous due to complex depositional environments and diagenetic processes, which complicate petrophysical evaluation and reservoir characterization (Lucia, 1999). This challenge is particularly evident in the Hartha Formation in central Iraq, where variations in lithology and pore system lead to uncertainty in estimating reservoir properties. Previous studies on the Hartha Formation have mainly relied on conventional interpretation methods, with limited integration of electrofacies analysis, leaving the relationship between log responses, depositional facies and reservoir quality insufficiently constrained. Although useful, traditional log interpretation methods require computational platforms that can manage large datasets, carry out multi-parameter modelling, and produce consistent interpretations across several wells (Asquith and Krygowski, 2004; Schlumberger, 2019). Al-Baldawi (2016) demonstrated that IPSOM can effectively classify lithology and reservoir units from well log data. The Xn Oil Field is located southeast of Baghdad's city, between 20 and 25 km from the city center inside the administrative boundaries of the governorates of Wasit and Baghdad (Fig.1). This study aims to improve reservoir characterization of the Hartha Formation in the Xn Oil

Field by integrating conventional petrophysical analysis with IPSOM-based electrofacies classification to better capture reservoir heterogeneity and identify productive intervals.

2. Geology and Tectonic Framework

Iraq's geology and tectonic evolution were significantly impacted by the opening and closing of the Palaeotethys and Neotethys oceans. The surface geology of the Xn area is dominated by quaternary alluvial sediments, primarily from the Tigris River and its tributaries (Buday and Jassim, 1987). From the Late Cretaceous to the Tertiary, structural growth reduced accommodation space and diagenetic fluid circulation, which in turn compromised the preservation of porosity in the Hartha carbonates (Shakir et al., 2013). Iraq's geology and tectonic evolution were significantly impacted by the opening and closing of the Palaeotethys and Neotethys oceans. The surface geology of the Xn area is dominated by quaternary alluvial sediments, primarily from the Tigris River and its tributaries (Buday and Jassim, 1987). From the Late Cretaceous to the Tertiary, structural growth reduced accommodation space and diagenetic fluid circulation, which in turn compromised the preservation of porosity in the Hartha carbonates (Shakir et al., 2013). According to (Khorshid and Kadhm, 2015), the time slice maps of the base Lower Fars demonstrate that there are no faults in the Oligocene formations, whereas the seismic section indicates that there are faults in the deeper Formations.

3. Materials and Method

Quality control was systematically applied throughout the petrophysical analysis to ensure the reliability and geological consistency of the findings, as follows:

3.1. Top-Bottom Adjustment and Core-Depth Shift

Core depth shifting was applied to well EB-4 in order to address depth discrepancies caused by operational variables such as drill pipe stretch, core slippage, expansion or contraction during retrieval, and inaccurate depth recording. Table 1 summarises the core analysis of EB-4 that was used to resolve depth discrepancies. Following depth alignment, core-derived petrophysical data was compared to its corrected log depth and used to calibrate log interpretations. Table 2 provides a summary of the applied shifts and depth adjustments. In petrophysical research, precise depth matching between core and log data becomes essential because minor discrepancies can lead to serious interpretation issues (Tiab and Donaldson, 2016). The 7.3 m positive core-log depth correction required for the interval between 2042 and 2049.3 m indicates that the recovered core in Well EB-4 was located shallower than the actual logged depth. In order to ensure consistency in the petrophysical evaluation, the shift was performed to match the core depth with the corresponding depth in the wireline record, as shown in Table 3 below. This modification ensured a precise linkage with the lithological and petrophysical features of the Hartha Formation Fig. 2 by aligning the core porosity and permeability patterns with the neutron density and gamma-ray log values. Depth was considered suitable when core-log porosity trends showed the greatest correlation and the least amount of mismatch in lithological markers.

Table 1. Core data statistical summary of EB- 4

Parameter	Porosity %	Permeability(mD)
Number of samples	250	250
Minimum	2.18	0.02
Maximum	32.13	26
Mean	21.47	3.92
Median	23.12	2.10
Standard deviation	6.12	5.48
Interquartile range	17.08- 26.68	0.64- 5.61

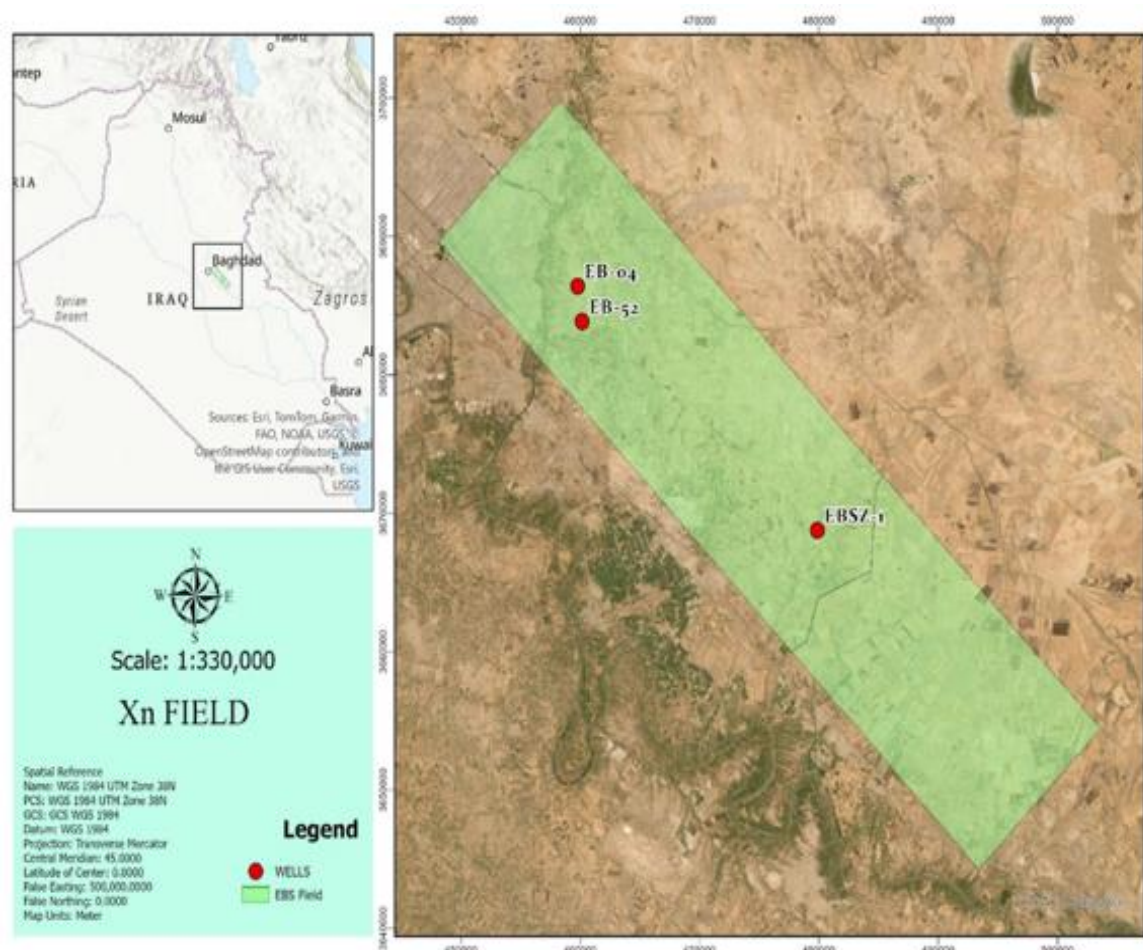


Fig.1. Location map of the of the studied area

Table 2. Depth adjustment of the wells under scope

Well no.	Top m.	Top corrected	Difference +/- m.	Bottom m.	Bottom corrected m.	Difference m.
EB-4	1863	1863.7	-0.7	2151.5	2151	0.5
EB-52	1898	1898.2	-0.2	2265.5	2264.7	0.8
EBSZ-1	2013	2011.8	1.2	2292	2292.3	0.36

Table 3. Core depth shifts calibration of EB- 4

Bottom (core depth) m.	Top (log) depth m.	Adjust m.
2042	2049.3	7.3

3.2. Neutron-Density Cross-Plot Normalisation

Neutron-density normalisation was performed by cross-plotting neutron porosity (ϕ_N) versus density porosity (ϕ_D) in pure carbonate intervals in order to assess measurement consistency. In a perfect limestone matrix, the data should exhibit a 1:1 trend; deviations from this trend may indicate tool offsets, environmental effects, or incorrect matrix assumptions (Ellis and Singer, 2007). Linear

correction functions were used where systematic deviations were observed between ϕ_N and ϕ_D . The reference population was selected from clean intervals of the Hartha Formation. The porosity data more closely matched the expected limestone response after normalisation, which reduced dispersion and improved the precision of subsequent petrophysical calculations (Schlumberger, 2019). Normalised results for wells EB-52 and EBSZ-1 are presented in Figs. 3 and 4, the precise matching of neutron and density porosity along the limestone line suggests that EB-4 did not require normalisation due to consistent tool calibration and minimal environmental corrections.

3.3. Lithology Identification

The lithology of carbonate and mixed carbonate-siliciclastic successions was distinguished using a Neutron-Density (N-D) cross plot, which provides one of the most reliable petrophysical methods for characterising matrix composition and porosity behaviour. The method is based on how changes in bulk rock density, pore fluid, and mineralogy affect the neutron and density logging tools differently. Plotting neutron porosity (ϕ_N) against density porosity (ϕ_D) using logs from well EB-4 (Fig. 5) enables quantitative lithology identification since data points corresponding to different lithologies cluster along distinct trends (Ellis and Singer, 2007). The Xn Oil Field is structurally divided into two main sectors, S1 and S2. This study covers both sectors, where the selected wells are distributed across these structural blocks to provide a comprehensive evaluation of the Hartha Formation reservoir.

4. Petrophysical Evaluation

4.1. Finding Shale Volume

By normalising the observed values across clean carbonate and shale reference intervals, shale volume (V_{sh}) was mainly calculated using gamma ray log responses. This method is frequently used in carbonate reservoirs to support porosity, saturation, and net pay estimates as well as to differentiate clean reservoir zones from shaly or non-reservoir intervals (Asquith and Krygowski, 2004). The Hartha Formation's reservoir quality was assessed using the ensuing V_{sh} distribution provided by Schlumberger (1989):

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

where IGR stands for gamma-ray index.

GR log = Gamma-Ray

Gamma-Ray minimum (clean sand or carbonate) is equal to GR min.

GR max is the shale's Gamma-Ray maximum. Table 4 outlines the gamma ray baseline parameters can be used to calculate the shale content in the Hartha Formation (Asquith and Krygowski, 2004).

Table 4. Values of variables needed for the calculation of shale volume of the Hartha Formation

Wells	Number of values	Minimum	Maximum
EB-52	366	9.5	69.8
EB-4	2032	13.2	54.56
EBZ-1	281	15	45.85

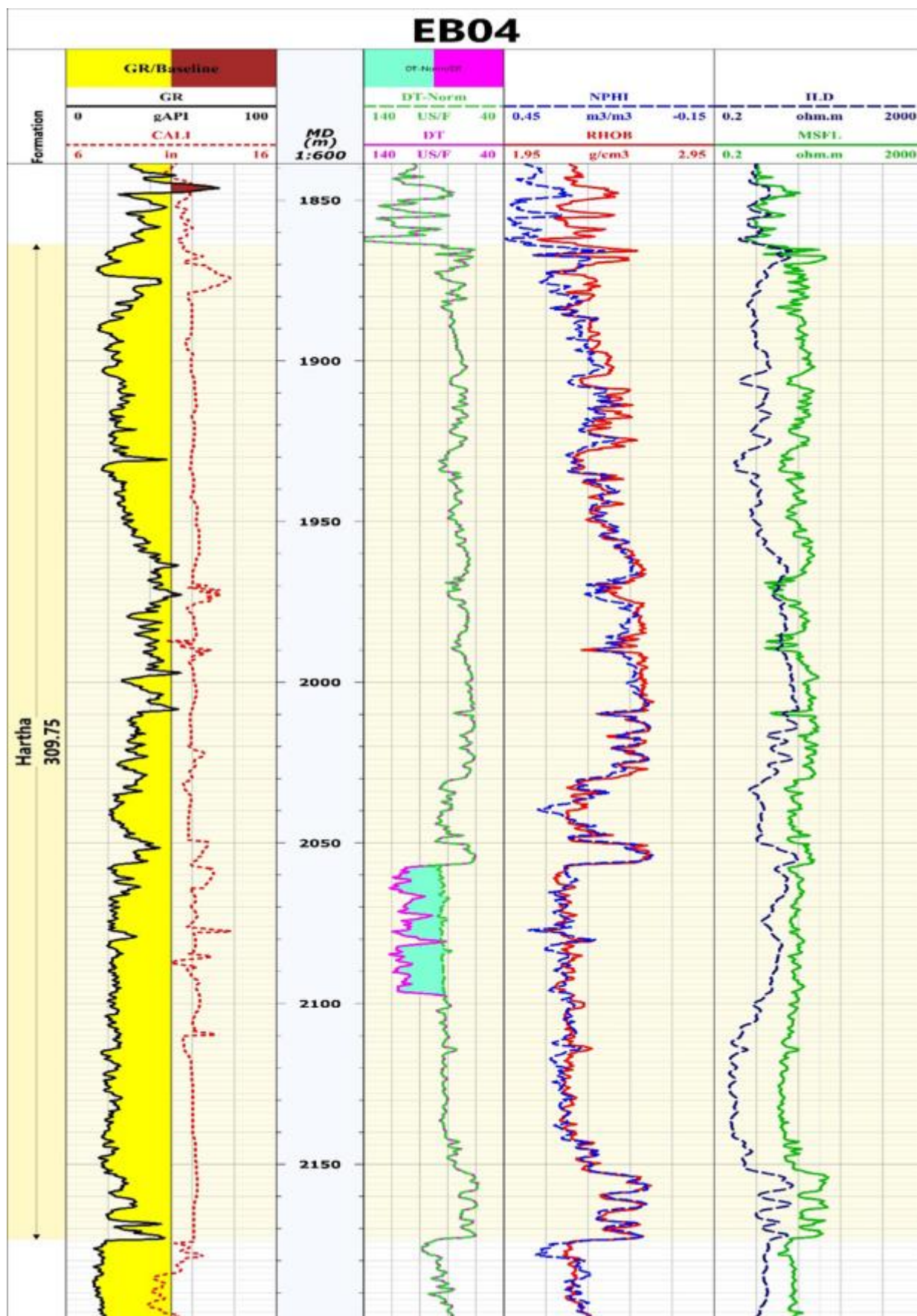


Fig.2. Corrected log data integration of EB-4

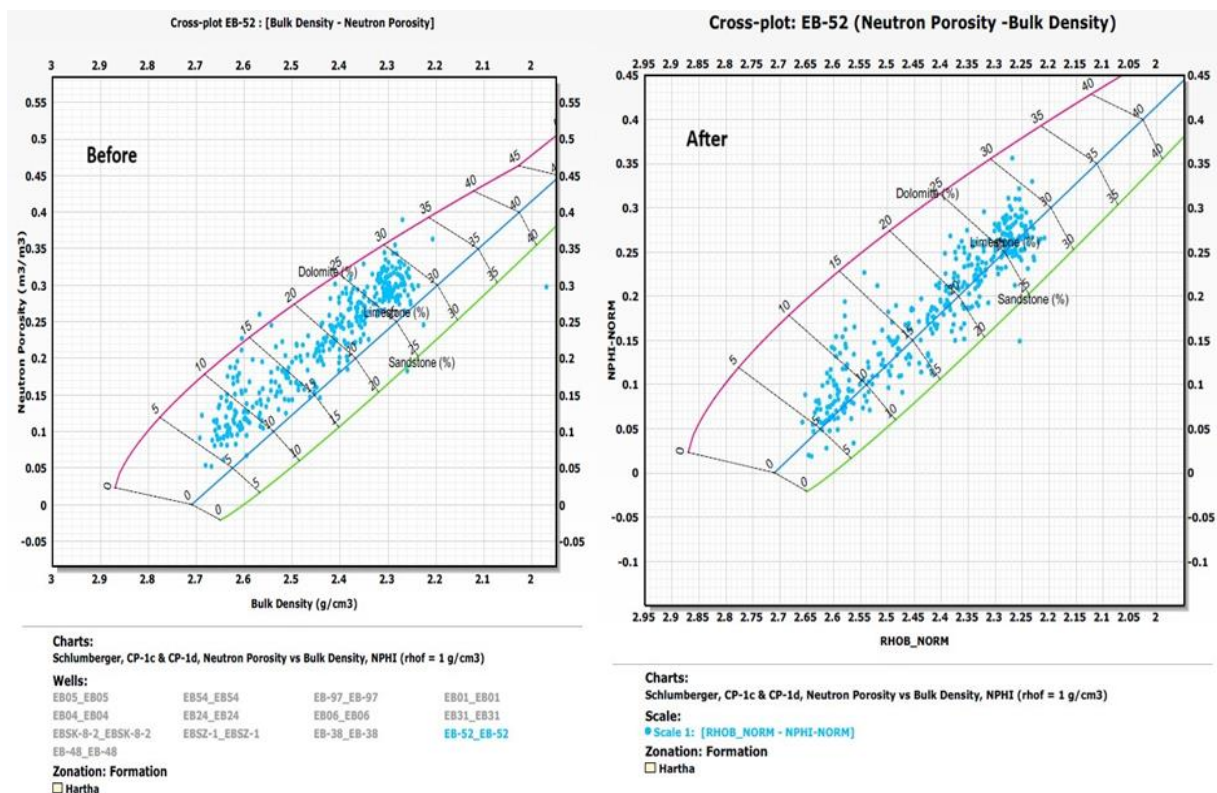


Fig. 3. Neutron-Density cross plot showing the process of normalisation of EB- 52 well

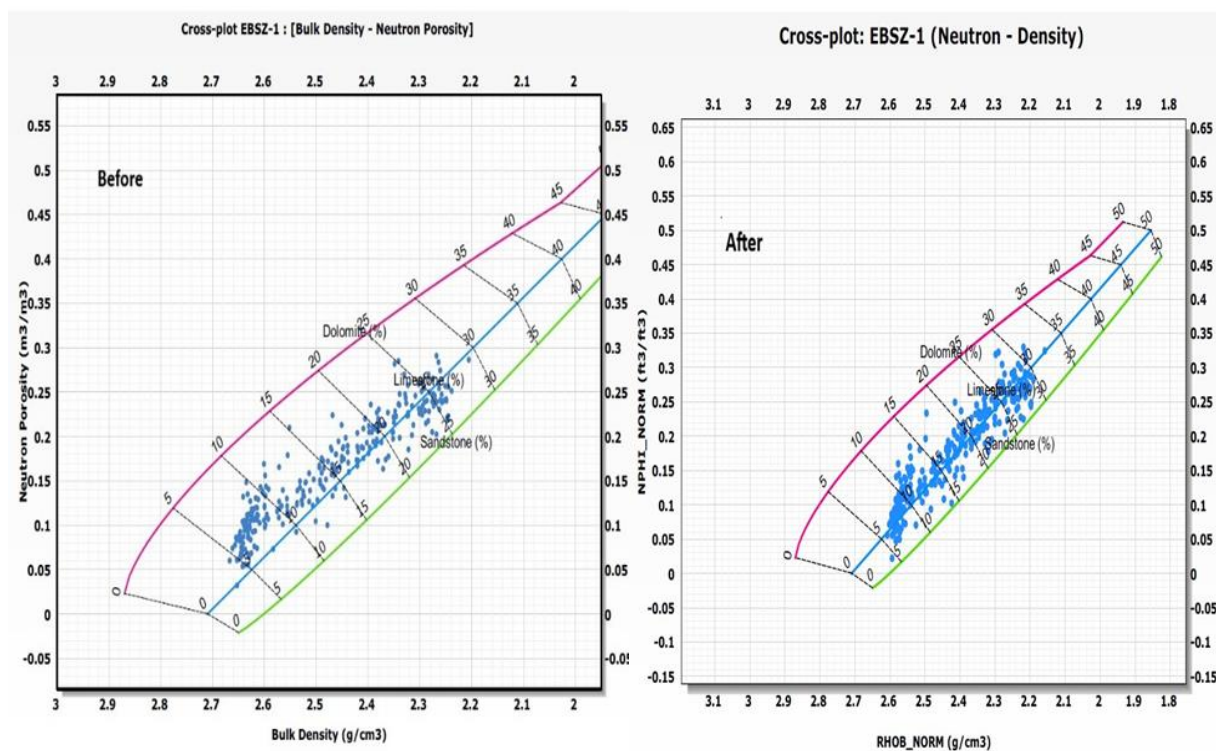


Fig. 4. Neutron-Density cross plot showing the process of normalisation of EBZ-1 well

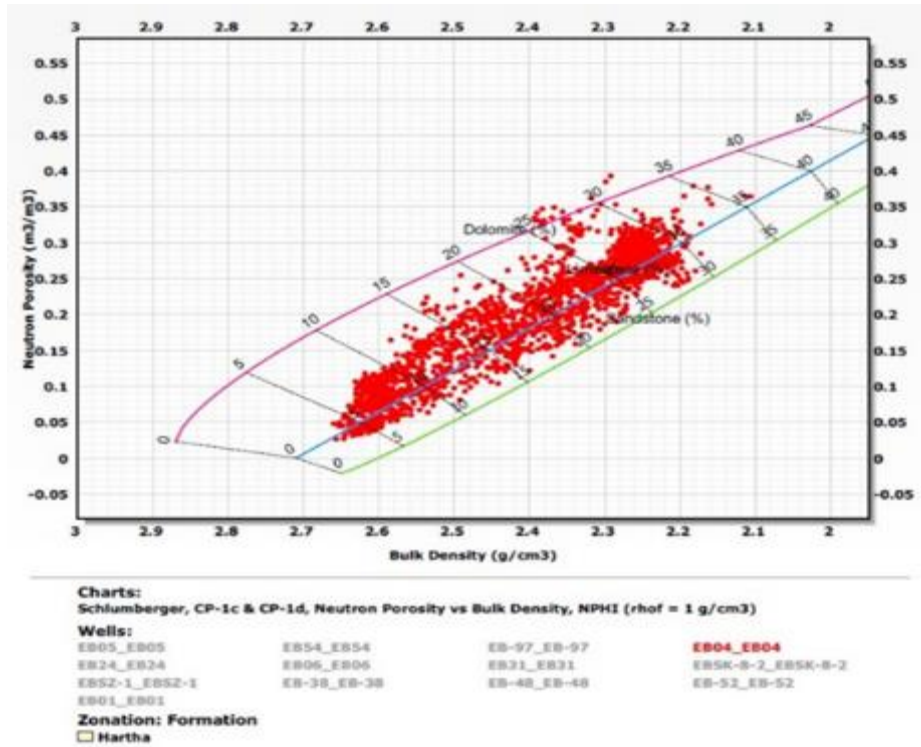


Fig. 5. Carbonate lithology of the Hartha Formation identified by N- D cross plotting

4.2. Porosity Measurement

Density and neutron wireline logs were used in conjunction with core data for calibration to estimate the porosity of the Hartha Formation. Neutron porosity provided information on the hydrogen content of the formation, while density porosity was computed from bulk density logs under the assumption of a carbonate matrix. In order to increase the accuracy of porosity estimates in carbonate intervals, average density–neutron porosity were used, and effective porosity was found by adjusting total porosity for shale volume. Log derived porosity estimates were calibrated and verified against laboratory - measured core porosity from well EB-4, leading to enhanced accuracy of reservoir characterisation (Serra, 1984; Schlumberger, 1989; Asquith and Krygowski, 2004).

$$\Phi_{\text{eff}} = \Phi_T(1 - V_{\text{sh}}) \quad (2)$$

While Φ_{eff} is the effective porosity and Φ_T is total porosity.

$$\Phi_{\text{Den.}} = \frac{\rho_{\text{matrix}} - \rho_b}{\rho_{\text{matrix}} - \rho_f} \quad (3)$$

Where: ρ_{matrix} is the grain density, ρ_b = extracted from the density log, and ρ_f = fluid density, assumed based on formation water and hydrocarbon properties.

Table 5. The parameters of different minerals and fluids

Well ID	RHOB shale g/cm ³	RHOB fluid g/cm ³	NPHI shale v/v
EB-4	2.4	1.22	0.4
EB-52	2.4	1.2-1.25	0.4
EBZ-1	2.4	1.22	0.4

4.3. Determination of Water and Hydrocarbon Saturation

In accordance with typical carbonate reservoir procedures, water saturation in the the Hartha Formation was measured by using Archie's equation based on effective porosity and actual formation resistivity. Hydrocarbon saturation was calculated as:

$S_h = 1 - S_w$. When backed by quality controlled log and core data, widely applied for clean to moderately shaly carbonate formations and yield accurate fluid distribution estimates (Archie, 1942).

$$S_w = \left(\frac{a \cdot R_w}{\phi_e^m \cdot R_t} \right)^{\frac{1}{n}} \quad (3)$$

Where:

a = tortuosity factor, m = cementation exponent, n = saturation exponent, R_w = formation water resistivity ($\Omega \cdot m$), R_t = true formation resistivity from ILD/MSFL logs ($\Omega \cdot m$) and ϕ_e = effective porosity (v/v). Effective porosity (ϕ_e) was used for water saturation calculation. Archie parameters that obtained from electrical core analysis of EB - 52 using the Pickett plot method, a log - log cross plot of porosity versus deep resistivity (Pickett, 1966). This approach accounts for facies - controlled pore type variations typical of the carbonate Hartha Formation (Lucia, 1999). Special core analysis (SCAL) data provided formation factor (F) values and regression of F versus porosity yielded the Archie parameters a and m following Archie's relationship $F = a \phi^{-m}$ (Archie, 1942). The parameters used for saturation calculation $R_w = 0.027 \Omega \cdot m$ at $81^\circ C$, $a = 1$, $m = 2.02$, and $n = 2$. Formation water resistivity was independently confirmed in well EB-52 using the Pickett plot 100 % water saturation line ($S_w = 1.0$, $w = 1.0 S_w = 1.0$) (Fig.6). The Pickett plot procedure, which uses a logarithmic relationship between effective porosity and deep resistivity, was used to find the formation water resistivity (R_w) of the Hartha Formation in well EB-52. R_w was estimated using the line representing 100% water saturation ($S_w = 1.0$), that produced a value of 0.0273 ohmm. Finally the lithostratigraphic succession of the reservoir, Ha1 is made up of carbonates that are comparatively clean, have intermediate porosity, and moderate GR values. Ha2 is identified as a tight, water-bearing interval due to its high GR response, high shale content, decreased N- D separation, and extremely low effective porosity. With lower GR values, more distinct limestone patterns on N-D crossplots, greater effective porosity, as well as increased resistivity especially in Ha3-c, which is the cleanest and best porous subunit Ha3 exhibits the best reservoir characteristics.

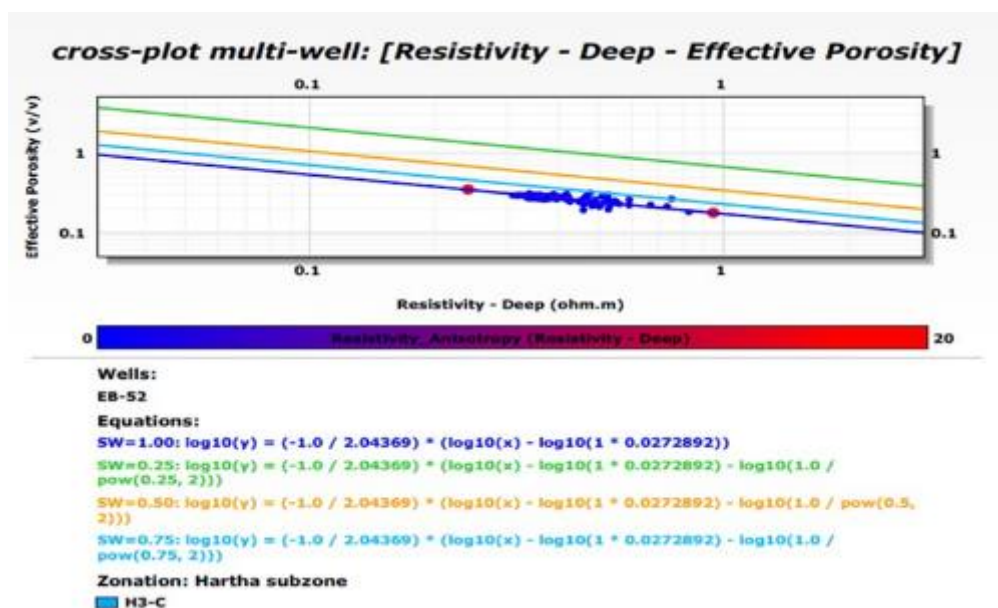


Fig.6. Crossplot showing the resistivity determination of water

4.4. IPSOM Electrofacies Analysis

The electrofacies were categorised using the Interactive Petrophysics Self-organising Maps (IPSOM) approach. The IPSOM approach was applied to the Hartha Formation. Multidimensional log responses are separated into discrete groups by an unsupervised neural network approach known as IPSOM, which shows petrophysical and lithological commonalities. After log normalisation, five primary logs were used to train the IPSOM model: gamma ray (GR), density (RHOB), neutron porosity (NPHI), deep resistivity (Rt), and shale volume (Vsh). The automated classification of clean carbonates, somewhat shaly intervals, and tight or water-bearing layers is made possible by this technique. The resulting electrofacies, which reflect the combined effects of lithology, porosity type, pore connectivity, and fluid content, enable high resolution zonation for volumetric assessment. The IPSOM classification was verified using core-derived petrophysical measurements from well EB-4. Clean, grain-supported carbonates have high resistivity, good density neutron separation, and low shale volume, all of which are compatible with superior electrofacies. However, because of their higher GR, higher Vsh, and lower porosity, mud-supported and argillaceous limestone intervals show weak or non-reservoir electrofacies. This is in line with the established relationships between carbonate fabric, pore type, and petrophysical behaviour (Lucia, 1999; Tiab and Donaldson, 2016). The electrofacies generated by IPSOM were then paired with quick-look interpretation results to offer a robust zonation framework for reservoir characterisation and volumetric evaluation throughout the examined wells. The IPSOM electrofacies (EFs) distribution in each is displayed in Table 5. Table 6 summarises the Hartha subunit (Ha1-b, Ha1-c, Ha2, Ha3-a, Ha3-c, and Ha3-d) (Fig.7) for the three investigated wells (EB-4, EB-52, and EBSZ-1). Groups EF-1 represent clean grain supported limestone (packstone grains), EF-2 relatively clean limestone with very little shale, EF-3 mud supported limestone or argillaceous carbonate classified as fair to poor reservoir, EF-4 shaly or tight carbonate, and EF-5 dense with tight carbonate.

Table 6. Electrofacies EF Lithology reservoir quality

The Harthazones	EB-4 Dominated electrofacies	Reservoir quality	EB-52 Dominated electrofacies	Reservoir quality	EBSZ-1 Dominated electrofacies	Reservoir quality
Ha1-b	EF-1 clean grain supported limestone	excellent	EF-1-EF-2	Good to excellent	EF-1-EF-2	good
Ha-c	EF-2, EF-3	Moderate	EF-2, Ef-3	Moderate	EF-3	Fair
Ha2	EF-3 with EF-2	Fair to moderate	Ef-3 with EF-4	Poor to fair	EF-3 with EF-4	Fair to poor
Ha3-a	EF-1	Excellent	EF1, EF2	Good to very good	Ef-1, EF-2	Good
Ha3-c	EF-2, EF-3	Moderate	EF-3	Fair	EF-3, EF-4	Fair to poor
Ha3-d	EF-4, EF-5	Poor	EF-4, EF-5	Poor	EF-4, EF-5	Poor

Three primary facies were identified by core-derived lithofacies across EB-4 and log responses across all wells, argillaceous to marly carbonate, mud-supported limestone, and grain-supported packstone/wackestone. Strong agreement was found when IPSOM electrofacies were calibrated using these facies: EF-1/EF-2 corresponded to high-quality grains-supported facies, EF-3 represented mud-supported intervals, and EF-4/EF-5 matched argillaceous or tight carbonates. This calibration shows that IPSOM electrofacies offer a solid framework for reservoir zonation in the Hartha Formation and successfully capture lithological and petrophysical variability.

4.5. Cutoff Determination

Accurate cutoff values for the Hartha Formation were determined in this study by integrating data from well logs and core measurements. Cutoff limits were established using crossplot analyses based on core and log data from well EB-4. The findings show a significant decrease in permeability below 9% porosity, which was subsequently chosen as the lower threshold for effective reservoir intervals in the Hartha Formation and the crucial porosity cutoff (Fig. 8) (Serra, 1984).

4.6. Water Saturation Cutoff

Analysis of the chosen wells using a crossplot between effective porosity and water saturation are clearly inversely correlated (Fig.9), with low-porosity intervals linked to high S_w values and zones with higher effective porosity greater than 0.20 typically showing lower water saturation < 0.40 v/v, indicating hydrocarbon-bearing intervals (Rider and Kennedy, 2011). A cutoff envelope was used to separate pay from non-pay zones. Based on cluster analysis and calibration using core data, a water saturation cutoff of $S_w \leq 0.60$ was chosen to define effective pay, while intervals with S_w greater than 0.60 were categorised as non-pay or water-bearing (Worthington, 2000). The selected cutoffs are technical cutoffs that could be enhanced using economic and production data. The porosity cutoff for the Hartha Formation was determined using the core porosity - core permeability crossplot shown in Fig. 10. The findings show a significant decrease in permeability at roughly 9 - 10% porosity, indicating that rocks with porosity below this threshold should not be able to maintain efficient fluid flow. As a result, the lower limit for possible reservoir intervals was set at a porosity value of 10 v/v.

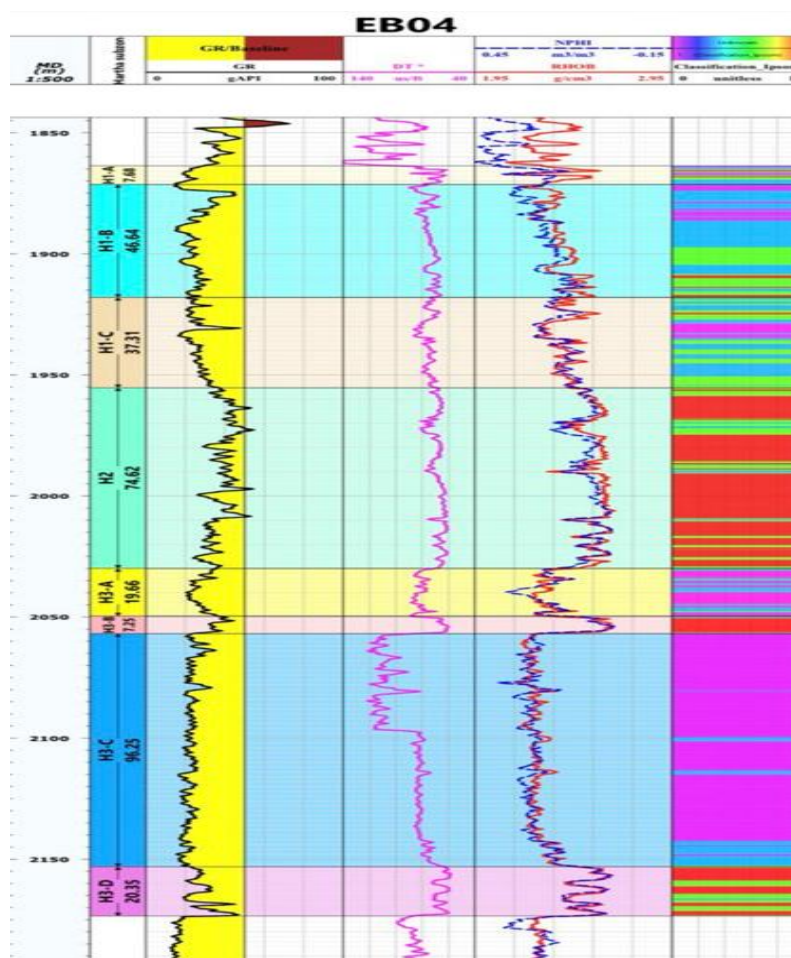


Fig.7. Zoning of the Harthareservoir using IPSOM and quick look interpretation

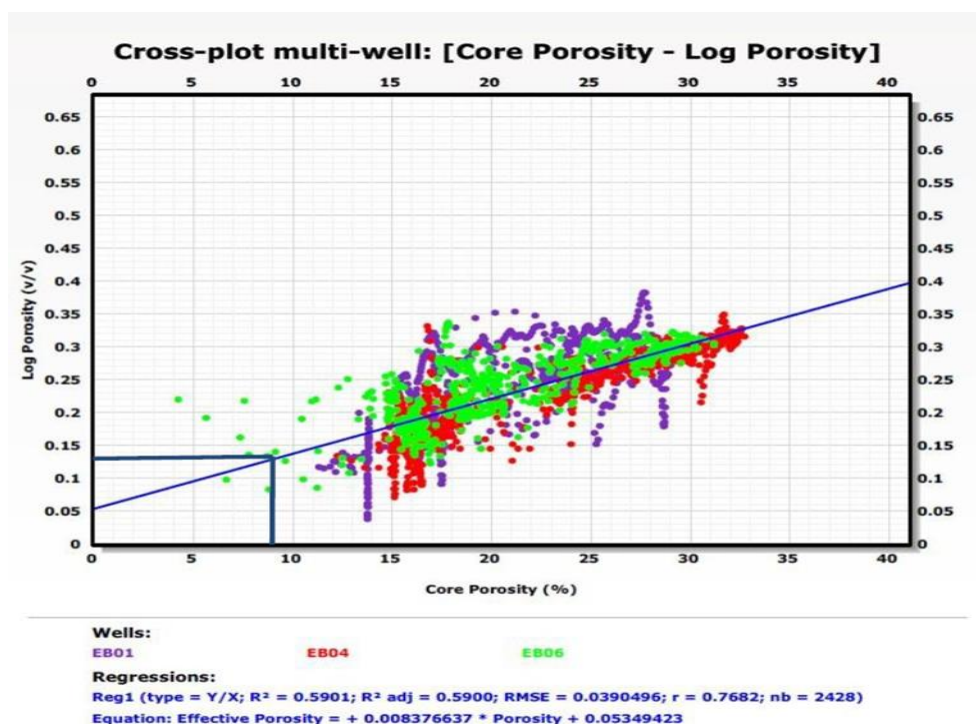


Fig. 8. Crossplot of core porosity vs. log porosity verifying the accuracy of log-derived porosity following core data calibration

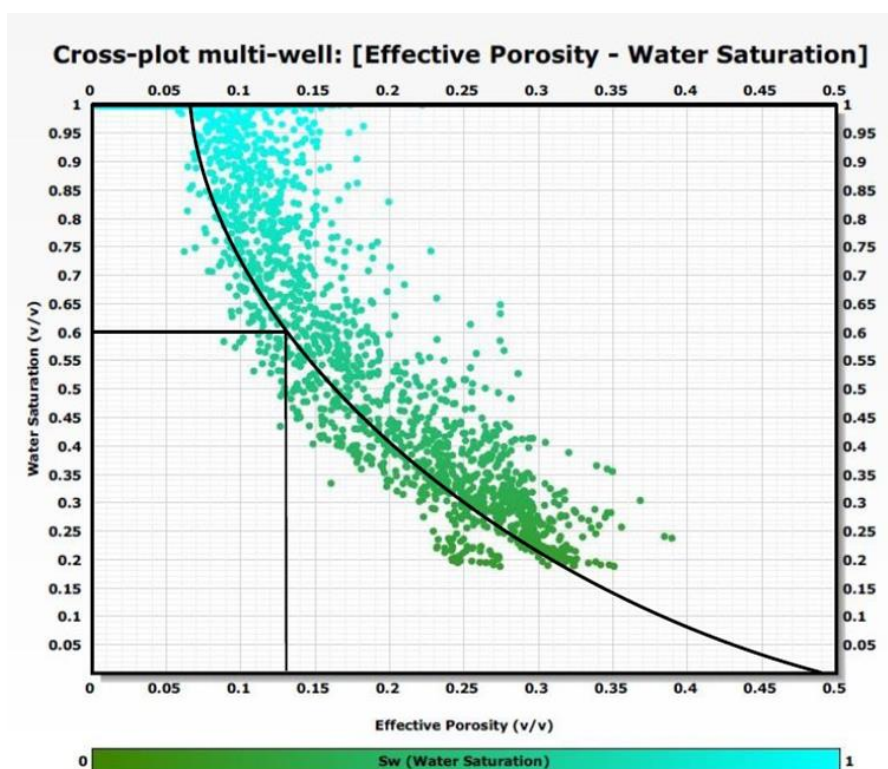


Fig.9. Multi well crossplot of effective porosity versus water saturation for the Hartha Formation

5. Results

The petrophysical analysis of well EB- 4 revealed considerable vertical heterogeneity in the Hartha Formation. Because of their low to moderate porosity and high water saturation, the Ha1 unit in Fig. 10

has a limited hydrocarbon potential. The Ha2 unit is the weakest reservoir interval and a non-productive zone because of its nearly complete water saturation and very low effective porosity. Reservoir quality significantly increases over the Ha3 interval. Because of its superior porosity and low hydrocarbon saturation, Ha3-a shows better pore formation. Ha3-c, which has the highest porosity, the lowest shale volume, and the highest hydrocarbon saturation, is found to be the finest reservoir unit in EB-4. In contrast, Ha3-b and Ha3-d are water-bearing and have poor reservoir properties. Ha3-c and Ha3-a are typically the most promising hydrocarbon-bearing zones in well EB-4, with the remaining units mostly serving as non-reservoir or water-dominated intervals (Table 7).

Table 7. Summary of petrophysical properties for well EB-4 in the Hartha Formation

Reservoir units	VSH (v/v)	PHIT (v/v)	PHIE (v/v)	SW (v/v)	Sh (v/v)
Ha1-a	0.402	0.227	0.198	0.598	0.402
Ha1-b	0.090	0.207	0.175	0.821	0.179
Ha1-c	0.101	0.214	0.193	0.854	0.146
Ha2	0.186	0.095	0.057	0.970	0.030
Ha3-a	0.102	0.267	0.246	0.579	0.421
Ha3-b	0.162	0.092	0.058	0.943	0.057
Ha3-c	0.070	0.295	0.281	0.594	0.406
Ha3-d	0.113	0.122	0.099	0.921	0.079

The Hartha Formation shows considerable vertical variability, with shale composition, porosity development, and water saturation all having a major impact on reservoir quality, according to the petrophysical interpretation of well EB-52, Table 8. Despite having a moderate porosity and a rather clean carbonate lithology, the Ha1 unit only contributes a small and erratic amount of pay due to the high water saturation in the area. Because of its high water saturation, lower porosity, and higher shale content, Ha2 is classified as a low quality, unproductive interval. The Ha3 unit, on the other hand, represents the main reservoir section. The main hydrocarbon-bearing zone, Ha3-c, has low gamma-ray values, high effective porosity, decreased water saturation, increasing resistivity, and continuous net-pay development. While subunits Ha3-a and Ha3-b show modest reservoir quality, Ha3-d is primarily water-bearing. By demonstrating that hydrocarbon accumulation in EB-52 is mostly concentrated in the cleaner, diagenetically enhanced carbonate facies of Ha3-c (Fig. 11), the results generally illustrate the great vertical heterogeneity of the Hartha Formation.

Table 8. Summary of petrophysical properties for well EB-52 in the Hartha Formation

Reservoir units	VSH (v/v)	PHIT (v/v)	PHIE (v/v)	SW (v/v)	Sh (v/v)
Ha1-a	0.141	0.212	0.183	0.616	0.384
Ha1-b	0.111	0.206	0.183	0.875	0.125
Ha1-c	0.111	0.223	0.201	0.985	0.015
Ha2	0.204	0.090	0.049	0.999	0.001
Ha3-a	0.120	0.251	0.227	0.961	0.093
Ha3-b	0.173	0.079	0.043	1.000	0.00
Ha3-c	0.095	0.285	0.266	0.968	0.032
Ha3-d	0.119	0.147	0.122	0.941	0.059

The Hartha Formation has significant vertical variability, with reservoir quality varying significantly between its stratigraphic subdivisions, according to the petrophysical interpretation of Well EBSZ-1 in Table 9. Despite having a moderate porosity and a rather clean carbonate lithology, the Ha1

interval is severely affected by excessive water saturation, which results in limited and erratic pay. Because of its increased shale volume, reduced effective porosity, muted resistivity response, and consistently high water saturation, Ha2 is classified as a poor-quality, mostly water-bearing interval. In contrast, the primary reservoir part of EBSZ-1 consists of the Ha3 unit. Ha3-c, which has low gamma-ray values, relatively high effective porosity, reduced water saturation, strong resistivity responses, and continuous net-pay development, is the most beneficial hydrocarbon-bearing zone. Subunits Ha3-a and Ha3-b exhibit intermediate reservoir characteristics with localised hydrocarbon potential, whilst Ha3-d is mainly water - bearing. Hydrocarbon accumulation in EBSZ-1 is concentrated in the cleaner and diagenetically improved carbonate facies of Ha3-c, demonstrating the substantial vertical variability and facies influence on reservoir performance within the Hartha Formation (Fig.12).

Table 9. Summery of petrophysical properties for well EBSZ-1 in the Hartha Formation

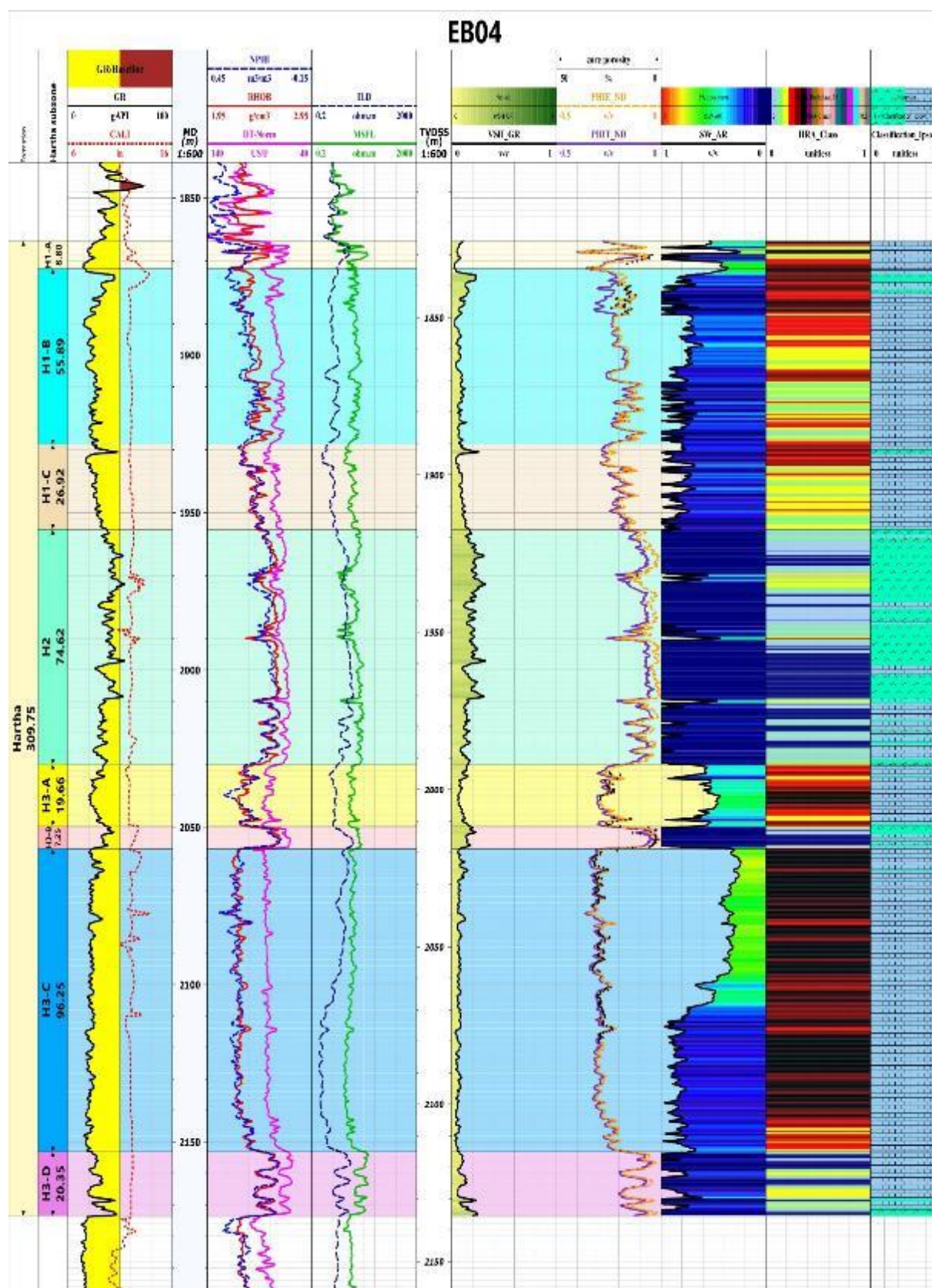
Reservoir units	VSH (v/v)	PHIT (v/v)	PHIE (v/v)	SW (v/v)	Sh (v/v)
Ha1-a	0.093	0.177	0.158	0.620	0.380
Ha1-b	0.101	0.224	0.203	0.506	0.944
Ha1-c	0.092	0.221	0.202	0.902	0.098
Ha2	0.123	0.101	0.076	0.972	0.028
Ha3-a	0.099	0.219	0.199	0.930	0.070
Ha3-b	0.110	0.109	0.087	0.955	0.045
Ha3-c	0.088	0.304	0.286	0.611	0.389
Ha3-d	0.103	0.143	0.122	0.944	0.056

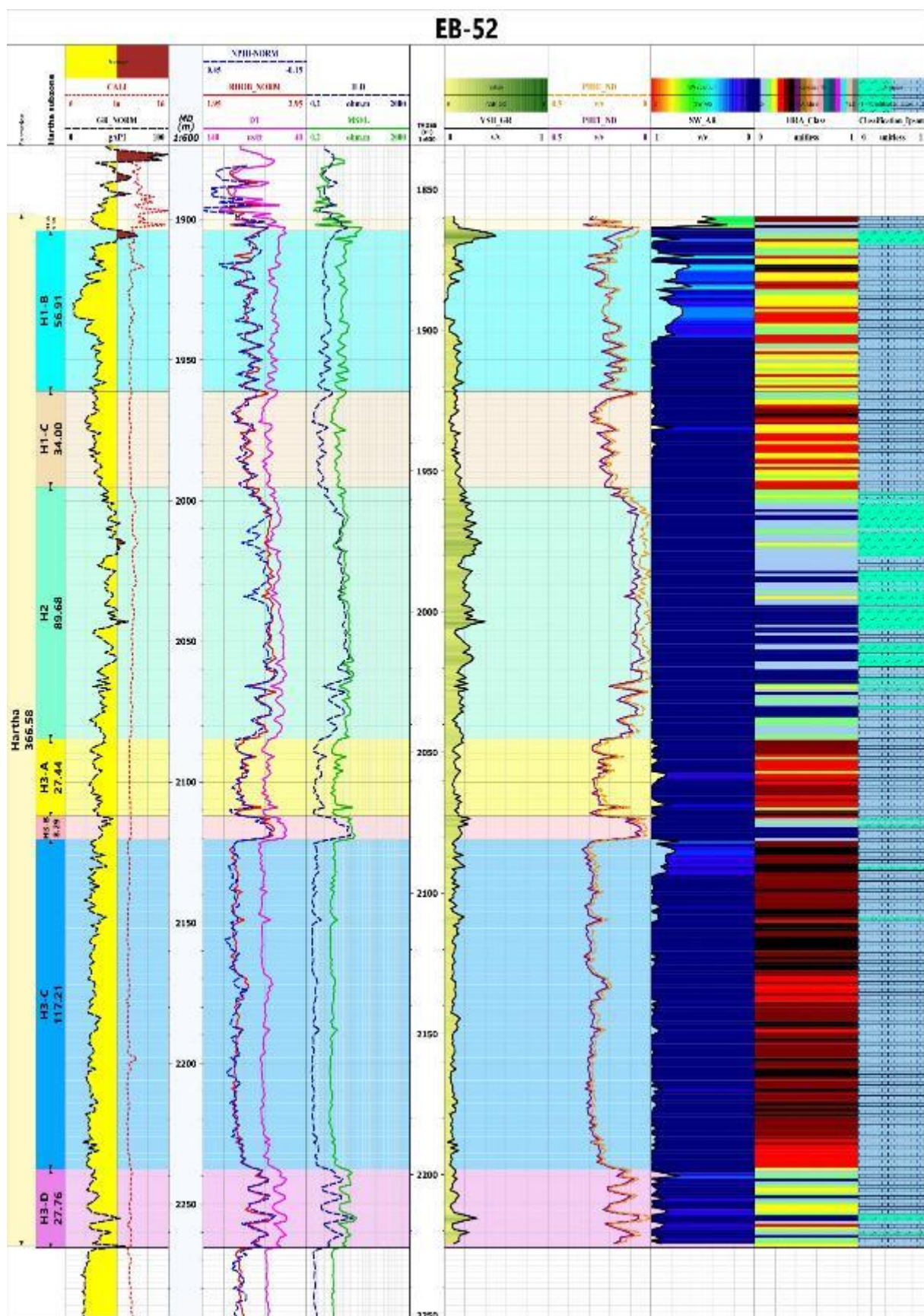
5.1. Net Pay Thickness Results

The results demonstrate that the significant regional variation in net pay across the field is primarily influenced by depositional facies and diagenetic processes. While micritic or argillaceous limestones with more shale and less porosity have smaller pay intervals, clean, grain-supported shoal and inner ramp limestones are associated with thick pay zones (Al-Juboury and McCann, 2013). The calculated net pay thickness Table 10 shows that the Hartha Formation in the Xn oil field includes numerous producing intervals with different reservoir quality and thickness. The greatest total net pay thickness of well-4 indicates the presence of dense laterally continuous hydrocarbon bearing zones. These pay zones are mostly located in reservoir units Ha1 and Ha3, where limited shale volume and relatively high effective porosity promote favorable hydrocarbon saturation. The continuity and thickness of net pay in EB-4 indicate a structurally and diagenetically beneficial location within the field, which is likely influenced by enhanced pore preservation and dissolution-related porosity development.

Table 10. Summary of the net pay thickness calculation for the reservoir

Well	Top Depth m.	Bottom m.	Total thickness of net pay (m)
EB-4	1863.7	2173.31	61.505
EB-52	1899	2265	3
EBZ-1	2013	2292	44





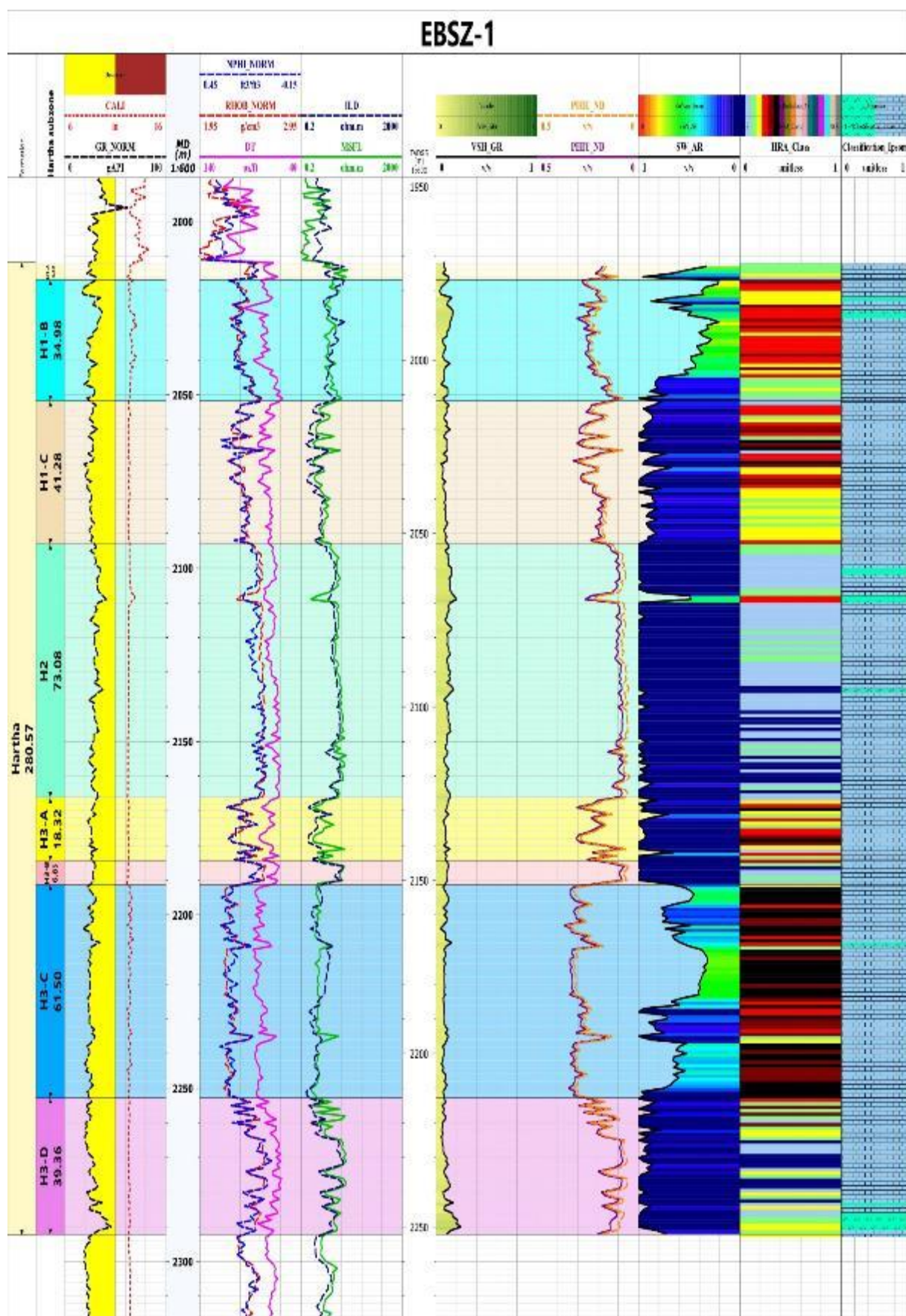


Fig.12. Distribution of total net pay thickness for EBZ-1 well

6. Discussion

Strong vertical heterogeneity is revealed by the integrated petrophysical investigation of the Hartha Formation, which is mainly governed by fluid distribution, diagenetic processes, and lithological variation. While core log depth matching and top - bottom corrections guaranteed precise alignment between core measurements and wireline logs, neutron density normalisation and lithology discrimination enhanced the consistency of porosity estimates. In every well under study, Ha1 exhibits a moderate and irregular reservoir potential, Ha2 continuously acts as a poor-quality, water bearing interval $> 60\%$, and Ha3 especially Ha3- c emerges as the primary reservoir unit with continuous net pay, lower water saturation, and higher effective porosity exceeding 0.20 v/v. With accurately identifying high-quality flow units in Ha3-c and distinguishing them from lower quality facies, the IPSOM categorisation confirms these conclusions. All things considered, the integrated workflow offers a solid and trustworthy foundation for identifying productive zones within the Hartha Formation and characterising reservoirs.

7. Conclusions

Through strict data quality control and calibrated workflow, Schlumberger Techlog integrated petrophysical analysis successfully characterized the Hartha Formation in the Xn oil field. The findings show significant vertical heterogeneity, the Ha2 unit functioning as a poor water bearing interval with very low effective porosity 0.049 - 0.076 v/v and very high water saturation 0.97 - 1 v/v. While Ha3 unit specifically Ha3-c representing the primary productive reservoir with continuous net pay, lower shale volume 0.07 - 0.09 v/v, lower water saturation 0.59 - 0.61 v/v, and higher effective porosity 0.281 - 0.286 v/v. High quality reservoir facies were successfully separated from non reservoir intervals by IPSOM electrofacies analysis EF- and EF-2 represent high quality reservoir facies. The distribution of net pay varies geographically, with EB-4 exhibiting the highest cumulative net pay equal 61.5 m. due to favorable diagenetic and depositional conditions. All things considered, the applied workflow offers a solid foundation for determining productive zones and assisting with decisions about reservoir development in the Hartha Formation.

8. Recommendation

Future studies should focus on the Ha3-c unit, the main productive unit of the Hartha Formation, and include comprehensive core and log examinations to improve saturation and permeability estimates. Increasing the use of machine learning techniques like IPSOM in conjunction with stringent data quality control and depth matching will improve rock type and reservoir characterisation. It is also recommended to apply 3D seismic and structural studies to better evaluate lateral heterogeneity and encourage optimal reservoir development.

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