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Chinedu O Igili

chiigili@yahoo.com

Novena

Angelica E Ogbimi

Dennis Osadebay University

Eze M. Okoro

Nnamdi Azikiwe University

John E. Okonkwo

Novena University

Erepamo J. Omietimi

University of Pretoria

Felix I. Chinyem

Delta State University

Onne A. Okpu

Heriot-Watt University

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INTEGRATED LITHOFACIES ANALYSIS AND RESERVOIR CHARACTERIZATION OF THE “NANYA” FIELD, OFFSHORE NIGER DELTA

Chinedu O. Igili^a, Angelica E. Ogbimi^b, Eze M. Okoro^c, John E. Okonkwo^a, Erepamo J. Omietimi^{d,e}, Felix I. Chinyem^f, Onne A. Okpu^g

^aDepartment of Energy and Petroleum Studies, Novena University, Ogume, Nigeria

^b Department of Geology, Dennis Osadebay University, Asaba, Nigeria

^cDepartment of Applied Geophysics, Nnamdi Azikiwe University, Awka, Anambra State, Nigeria

^dDepartment of Geology, University of Pretoria, Private Bag X20, 0028, Pretoria, South Africa

^eDepartment of Geology, Niger Delta University, Wilberforce Island, Amassoma, 560103, Nigeria

^fDepartment of Geology, Delta State University, Abraka, Nigeria

^gInstitute of GeoEnergy Engineering, Heriot–Watt University, Edinburgh, EH14 4AS, Scotland, United Kingdom

Corresponding author: Department of Energy and Petroleum Studies, Novena University Ogume,

e-mail: chiigili@yahoo.com, ORCID: <https://orcid.org/0000-0003-2313-2981>

ABSTRACT

This study integrates lithofacies analysis and petrophysical analysis to assess the Sand reservoir in the Nanya Field offshore in the Niger Delta. The combined processing of wireline log data (Gamma Ray, Resistivity, Density, Neutron, Sonic, and Photoelectric) from wells 1-1 and 2-1 involved the following steps: reservoir zonation, facies classification, petrophysical assessment, inter-well correlation, and quality ranking. The K Sand was identified as the most important hydrocarbon-bearing zone on the basis of zonation work, which subdivided the K Sand into four flow zones (I–IV) based on shale barriers and log signatures. The facies analysis, based on crossplots of density–neutron, M–N, matrix identification and PEF–Density data, indicated a primary reservoir facies of quartz–dominated sandstone, which is mainly present in Zone II of Well 1-1. The petrophysical results indicate that Well 2-1 has better reservoir properties with an average of 0.88 net-to-gross, 12% shale, 18% effective porosity, 14% water saturation, and 12.55 mD permeability compared with Well 1-1 which has an average of 0.78 net-to-gross, 22% shale, 15% effective porosity, 23% water saturation, and 8.66 mD permeability. The lateral flow continuity in the Agbada Formation is reasonable based on the correlation of the wells. Based on quality ranking, Zone III was identified as the best target due to low shale content, high porosity/permeability and low water saturation, followed by Zone IV. Overall, facies discrimination and petrophysical evaluation further enhances reservoir characterization, aids in understanding the heterogeneity, and guides reservoir development and well-placement strategy for the Nanya Field.

Keywords: Niger delta basin, Reservoir characterization, Mineralogical composition, reservoir architecture, Crossplot analysis

1.0 INTRODUCTION

Reservoir characterization is a critical aspect in the exploration and production of hydrocarbons, as it aids in providing detailed understandings of the geometry of reservoirs, their lithological heterogeneity, petrophysical attributes, and the distribution of fluids within them (Adeoti et al., 2020; Al-Aani, 2024). The use of geological and petrophysical data to reduce uncertainties in the estimation of reserves and field development planning has become more critical in increasingly complex and heterogeneous reservoirs (Akinsanmi et al., 2022; Adeoti et al., 2020). Reservoir characterization involves a synthesis of geological, geophysical, and petrophysical data that can be used to assess reservoir quality, spatial continuity, and reservoir production performance. Petroleum accumulations in the paratopic deposits of the Agbada Formation (Ehirim, 2022) are spread throughout the Niger Delta Basin which is one of the most productive petroleum provinces in the world. The reservoirs consist primarily of stacked sandstone bodies with interbedded sequences of shale deposited in fluvial, distributary channel, mouth bar and shallow marine environments. These reservoirs are laterally and vertically heterogeneous due to the complex depositional evolution of the basin, hence a comprehensive characterization of the basin to make efficient hydrocarbons development is necessary (Emujakporue & Ogagarue, 2022).

Lithofacies analysis is a key element of reservoir characterization as it gives information on mineral composition, depositional environment, reservoir geometry and reservoir quality related to facies. Conventional core samples are not always available and therefore, integrated petrophysical crossplot analyses (Density–Neutron, M–N, Matrix Identification (MID), and Photoelectric Factor–Density (PEF–DEN) analysis) can be used effectively to identify lithofacies and to interpret the depositional environment (Al-Aani, 2024). The use of these techniques in combination with quantitative petrophysical analysis can greatly aid in the characterization of the reservoir, including the evaluation of porosity distribution, permeability variability, shale content, and hydrocarbon saturation (Aigbedion & Iyayi, 2019; Al-Aani, 2024).

The “Nanya” Field is located within the Offshore Niger Delta and comprises reservoirs of hydrocarbons within the Agbada Formation of sandstone. Although there are proven commercial hydrocarbons in the field, spatial variations in reservoir quality, facies distribution and reservoir continuity call for detailed characterization for the guidance of future development activities. For this reason, the lithofacies analysis, petrophysical evaluation, reservoir correlation and reservoir quality assessment were integrated in this study to determine the development characteristics of the reservoirs and the intervals that have the best potential for development in the future. The integrated workflow used is a practical solution for improving reservoir understanding, minimizing development risks and maximizing hydrocarbon recovery in the “Nanya” Field.

While there is some overlap between the aforementioned studies, most have concentrated on conventional petrophysical evaluation with relatively rare use of advanced lithofacies discrimination techniques like the density–neutron, M–N, and Matrix Identification (MID), and Photoelectric Factor–Density (PEF–DEN) crossplots (Aigbedion & Iyayi, 2019; Attouman et al., 2025; Ibim & Piate, 2024; Igili et al., 2026). Therefore, facies distribution, reservoir continuity

and most productive reservoir intervals are often unclear. To overcome these shortcomings, this study combines lithofacies interpretation, petrophysical evaluation, reservoir correlation and flow-unit analysis to better characterize the Nanya Field. In particular, the study aims to define the field using integrated wireline logs, to characterize the reservoirs, to assess the reservoir architecture and continuity, to assess the impact of lithofacies on reservoir quality and heterogeneity, to rank the flow units in terms of their production potential, and to prioritize the most promising areas for future drilling and development. This study is important because it shows that an integration between advanced lithofacies discrimination approaches and petrophysical evaluation is a valuable tool for reservoir characterisation in data limited fields where there is no core data or seismic data. Further, the integrated methodology offers an effective solution for characterizing the complexity of the reservoirs, predicting reservoir quality and guiding development decisions within the Niger Delta Basin.

2. Geology of the Study Area

The Niger Delta Basin is one of the world's largest Tertiary deltaic basins and is the most prolific hydrocarbon basin in sub-Saharan Africa. The basin is located along the passive continental margin of the Gulf of Guinea, in the south of Nigeria, and covers an area of approximately 75,000 km², with sedimentary thicknesses greater than 12 km at the main depocentres (Doust and Omatsola, 1990). Geologically it stretches from the Benin Flank to the north-west, through the Calabar Flank to the east and into the deep water sector of the Gulf of Guinea. The evolution of the delta was driven by a variety of factors, such as the plate tectonic setting, thermal subsidence, significant sediment supply, gravity-driven deformation, and persistent delta progradation that started in the Paleocene (Igili et al., 2026; Khan et al., 2025).

This wider geology of the Niger Delta is illustrated in Fig 1, which also illustrates the general geology of the Niger Delta basin, the depobelts and the geologic framework of the tectonostratigraphic framework of the Niger Delta basin with the study area. The figure also shows the three main lithostratigraphic units of the petroleum system namely Benin, Agbada and Akata formations, which are discussed in more detail in Fig. 3.

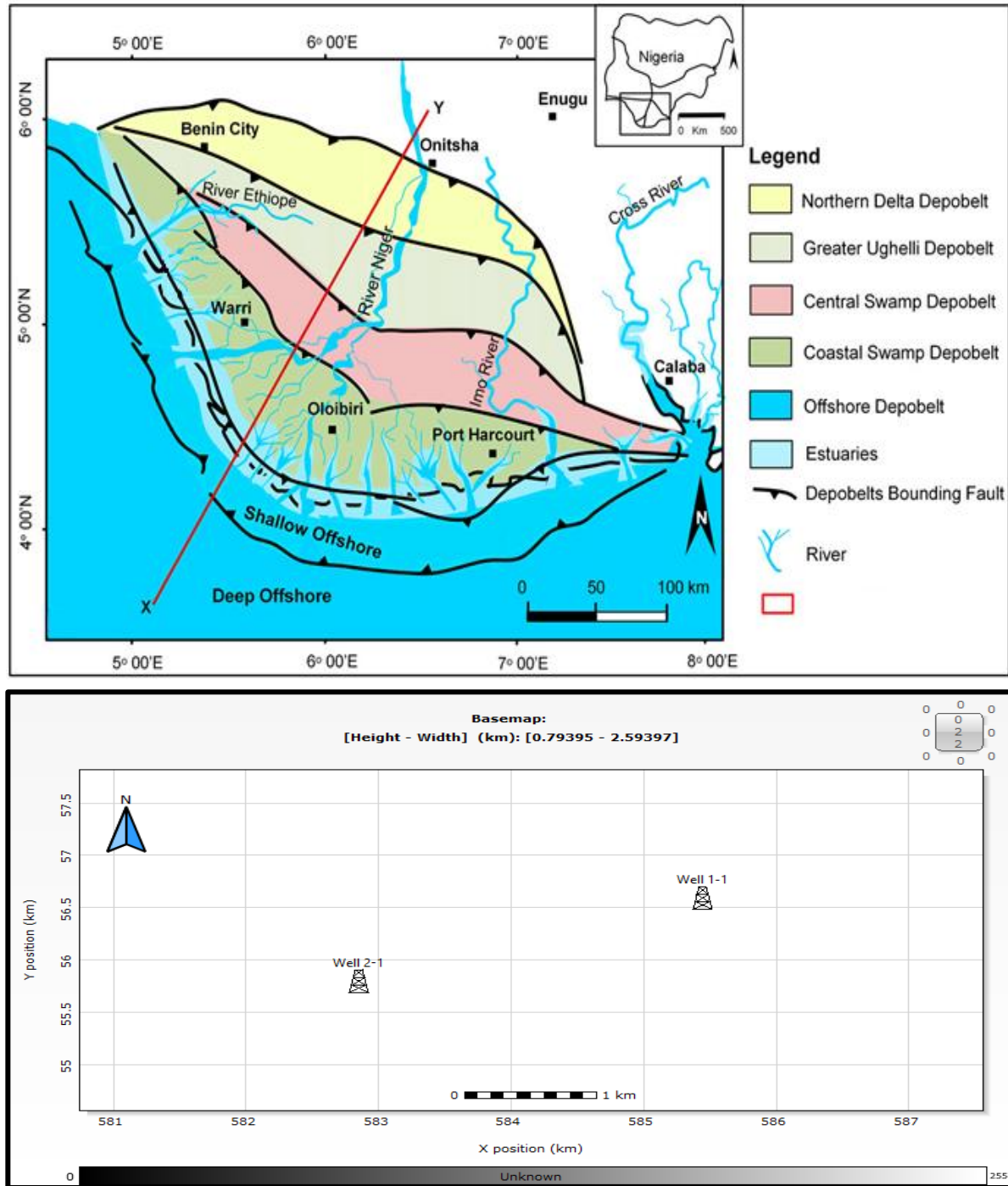


Fig. 1. A. Fig. 1. A. Regional geological structure of the Niger Delta Basin with the location of depobelts and the study area. Inset map of Nigeria shows the location of the Niger Delta. (modified from Evamy et al., 1984; Saugy and Eyer, 2003; Ogbe et al., 2020). B. Base map with location of Well X and Y.

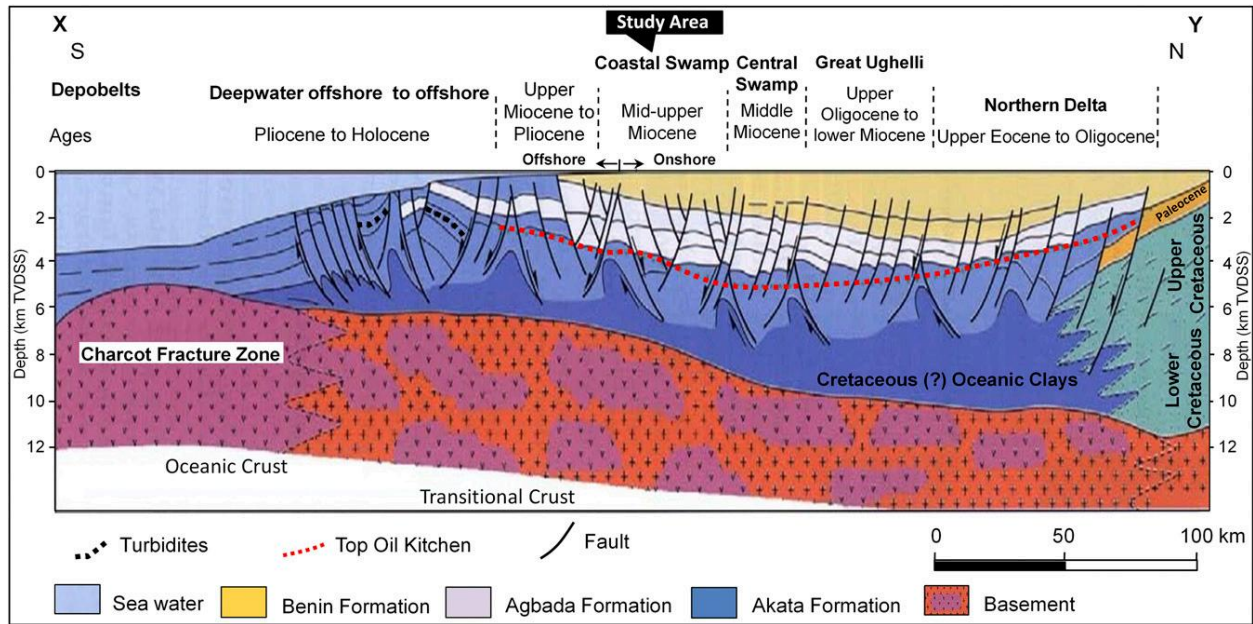


Fig. 2. Cross section of the Niger Delta Tectonostratigraphic Oil Province. Three diachronous lithostratigraphic formations have been used to mark the boundaries of the depobelts, and associated structures have been indicated (modified from Saugy and Eyer, 2003; Ogbe et 2020)

al.,2020).

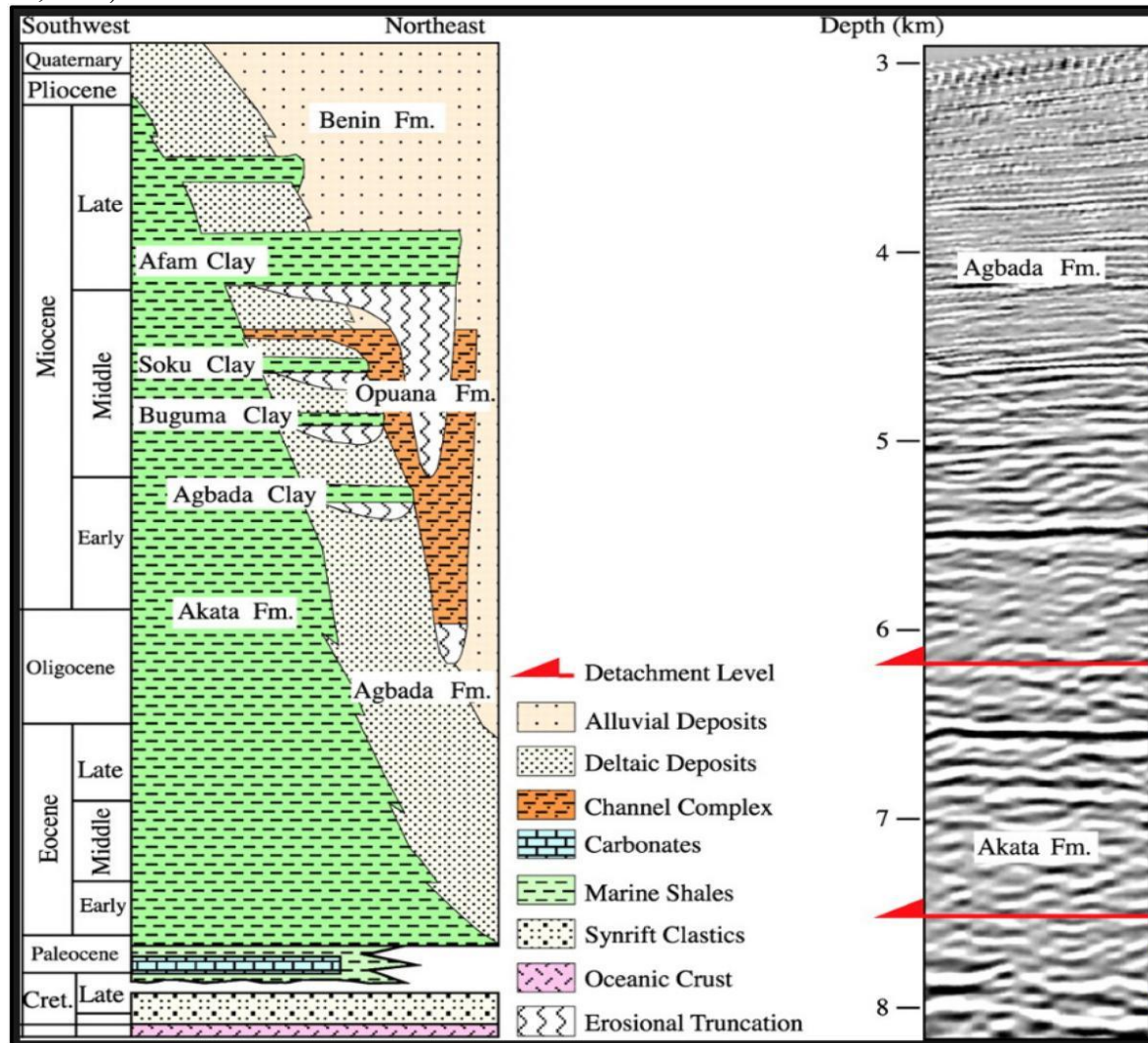


Fig. 3. Generalized stratigraphic framework of the Niger Delta Basin showing Akata, Agbada and Benin Formations.

The formation of the Niger Delta has been closely tied to the break-up of the super-continent Gondwana and the formation of the South Atlantic Ocean during the end of the Jurassic period and start of the Cretaceous period. The African and South American continental plates separated to form a series of intracratonic rift basins, which eventually changed to a passive continental margin when the rifting stopped (Burke et al., 1972; Whiteman, 1982). The region was thermally subsided during progressive cooling of the lithosphere after the rifting episode, providing the necessary accommodation space to allow thick sedimentary successions to be deposited (Short & Stauble, 1967; Evamy et al., 1978).

The cross-section of the Niger Delta Basin in Fig. 2 is a typical structure of the basin in the region. It shows gradual thinning of the sediment towards the basin margins, growth faults that originated within the ductile Akata Formation, and progradational stacking of the Benin, Agbada and Akata Formations (Evamy et al., 1978; Morley et al., 1996). The figure also shows how the shale was mobilized by sediment loading, with the formation of rollover anticlines that are the main structural traps for hydrocarbons, as depicted in Fig. 2.

The Niger Delta evolved in a series of delta progradations, creating a series of depobelts (each an abandoned delta front as the depositional area shifted landward in response to the Niger Delta seaward migration of sediment deposition) (Damuth, 1994). Structural style, thickness of sediments, reservoir architecture and the maturation history of hydrocarbons are the characteristics that differentiate individual depobelts (Doust & Omatsola, 1990). The study area falls into one of these depobelts as shown in Fig. 1, which is a regional geological framework that shows the progressive basinward migration of sedimentation and the corresponding structural development.

MATERIALS AND METHODS

Two wells in the Niger Delta Basin were drilled and wireline log data were acquired to assess two wells were drilled in the Niger Delta Basin and wireline logs were acquired to assess and characterize the reservoir zones of the "Nanya" Field using a lithofacies and petrophysical evaluation. Available data consisted of composite well logs, which were a combination of gamma ray, resistivity, density, neutron, and sonic readings. The original well names were anonymized as "1-1" and "2-1" and the field name was changed to "Nanya" Field. The first stage in reservoir characterization was to import the digital wireline logs into the Schlumberger's Techlog software. Quality assurance and quality control (QA/QC) were then implemented in great detail to ensure the reliability of the data. Log conditioning, depth alignment and environmental corrections to normalise log responses and make them more consistent were carried out next, prior to log interpretation. The standard industry approach to petrophysical evaluation was used, based on the gamma, density, neutron and resistivity curves. Empirical formulas were used to estimate core reservoir parameters – shale volume (V_{sh} ; %), effective porosity (Φ_e ; %), net-to-gross ratio (N/G ; %), water saturation (S_w ; %) and hydrocarbon saturation (S_h ; %). The water saturation was obtained from the Simandoux equation which is ideally suited to shaly sand formations like the Agbada Formation, where shale conductivity has measurable effect on the resistivity readings.

3.2 Well correlation

Lithological units were correlated between the two wells by using both gamma ray and resistivity logs. Stratigraphic continuity was determined and reservoir sand bodies and non-reservoir shale sections were separated by picking and matching marker shale horizons between the wells. The logs were plotted on True Vertical Depth Sub-Sea (TVDSS), with gamma ray plotted on a 0-150 API scale and resistivity plotted on a 0.2-2000 Ohm m scale.

3.3. Crossplot analysis

In the absence of core records for subsurface lithology interpretation, crossplot is considered one of the best techniques for lithological discrimination (Al-Aani, 2024). To aid lithofacies interpretation, a suite of crossplots was generated of log responses as a function of lithology, shale content, and gas presence, since all three influence log responses.

The crossplots of density and neutron were used to identify the reservoir lithology, and the Matrix Identification (MID) plot was used to differentiate lithology, gas zones and secondary porosity. Other correlations: Permeability–PHIE, Sw–PHIE, and PHIE–Vsh were explored as assessment of reservoir quality. The mineralogical composition of the reservoir intervals was also determined from the mineralogical cross plot for the M–N plot, calculated using the equations developed by Schlumberger (1989):

$$M = \left(\frac{\Delta t_f - \Delta t_{log}}{\rho_b - \rho_f} \right) * 0.01 \quad 1$$

$$N = \left(\frac{\phi_{NF} - \phi_N}{\rho_b - \rho_f} \right) \quad 2$$

where Δt_f is the interval transit time of the drilling fluid (189ms for fresh water, 185ms for salt mud) and Δt_{log} is the measured interval transit time from the sonic log, ρ_b is the formation bulk density calculated using the density log, ρ_f is the density of the drilling fluid (1g/cm³ for fresh water, 1.1 g/cm³ for salt mud), and ϕ_{NF} is the neutron porosity of the drilling fluid (assumed to be 1.0).

3.4. Computation of reservoir properties

Selected reservoir sand intervals were quantitatively evaluated using empirical relationships commonly used in the field and are summarized below: shale volume, total porosity, effective porosity, net-to-gross ratio, and water saturation.

3.4.1. Volume of shale (Vsh)

The gamma ray index (IGR) was first obtained from the gamma ray log for each reservoir interval, based on Schlumberger's (1989) relationship:

$$IGR = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})} \quad 3$$

GRlog is the gamma ray reading of the formation, GRmin is the minimum gamma ray reading for clean sandstones, and GRmax is the maximum gamma ray reading for shale. The gamma ray index was then converted to the volume of shale using the Larionov 1969 equation for the Tertiary rocks:

$$V_{sh} = 0.083 * (2^{3.7 * IGR} - 1) \quad 4$$

3.4.2. Total porosity (Ø)

Neutrality porosity and density porosity were added together to provide total reservoir porosity reading. Initial shale correction of neutron porosity values was done following the shale correction equation of Tiab and Donaldson (2015):

$$\emptyset N_{corr} = \emptyset N (V_{sh} * \emptyset N_{sh}) \quad 5$$

In this case, ØNcorr is the neutron porosity corrected for shale, ØN is the neutron log reading and ØNsh is the neutron porosity of shale. The porosity was then calculated based on density as per Asquith and Krygowski (2004):

$$\emptyset_{den} = \left(\frac{\rho_m - \rho_b}{\rho_m - \rho_f} \right) \quad 6$$

In which, the density-derived porosity (Øden), the matrix density (ρm), the formation fluid density (ρf), and the measured bulk density (ρb). The densities used were matrix density, ρma, for sandstone, 2.65 g/cm³ and fluid density, 1.0 g/cm³ (fresh water) or 1.1 g/cm³ (saline water). A shale corrected version of density porosity was also calculated:

$$\emptyset D_{\text{corr}} = \emptyset D (V_{\text{sh}} * \emptyset D_{\text{sh}}) \quad 7$$

Where the shale density porosity ($\emptyset D_{\text{sh}}$) remains constant and the corrected value ($\emptyset D_{\text{corr}}$). The combined neutron-density porosity was then calculated as:

$$\emptyset_{ND} = \emptyset_N + \emptyset_D / 2 \quad 8$$

With both neutron and density values shale-corrected, total corrected porosity was calculated as:

$$\emptyset_{ND\text{corr}} = (\emptyset_{N\text{corr}} + \emptyset_{D\text{corr}}) / 2 \quad 9$$

3.4.3. Water saturation

Water saturation was calculated using the model proposed by Simandoux (1963) which is appropriate for shaly sandstone reservoirs where the shale fraction makes a contribution to conductivity:

$$S_w = 0.4 * \frac{Rt}{\emptyset_{\text{corr}}^2} * \sqrt{\left(\frac{V_{\text{sh}}}{R_{\text{sh}}}\right)^2 + (5 * \emptyset^2 / R_w * Rt)} - \frac{V_{\text{sh}}}{R_{\text{sh}}} \quad 10$$

The water saturation (S_w) is a function of several factors, including the neutron-density total porosity ($\emptyset$), the true formation resistivity (Rt), the corrected neutron-density porosity ($\emptyset_{\text{corr}}$), and the shale resistivity (R_{sh}). In this case, hydrocarbon saturation (S_h) followed:

$$S_h = 1 - S_w \quad 11$$

3.4.4. Net-to-gross ratio (N/G)

The net to gross ratio is the percentage of clean, porous, permeable reservoir sand that is present in a reservoir, as a measure of reservoir quality (net thickness/gross thickness) higher numbers indicate higher quality reservoirs.

$$NTG = \frac{\text{Net Thickness}}{\text{Gross Thickness}} \quad 12$$

The following formula was used for the calculation of effective porosity:

$$\emptyset_e = (1 - V_{\text{sh}}) * \emptyset \quad 13$$

3.4.5 Permeability Estimation

Permeability was estimated empirically from effective porosity using established sandstone permeability relationships available within Techlog software. The resulting values provide relative comparisons of reservoir quality between the identified flow units.

3.5 Petrophysical Cut-offs

Petrophysical cut-off values were applied to distinguish productive reservoir intervals from non-reservoir units. Reservoir sands were identified using a gamma-ray value less than 75 API. Effective porosity greater than 10%, shale volume less than 35%, and water saturation less than 50% were adopted as the criteria for defining potential hydrocarbon-bearing reservoir zones.

4 RESULTS, INTERPRETATION AND DISCUSSION

4.1 Reservoir Architecture of Well 1-1

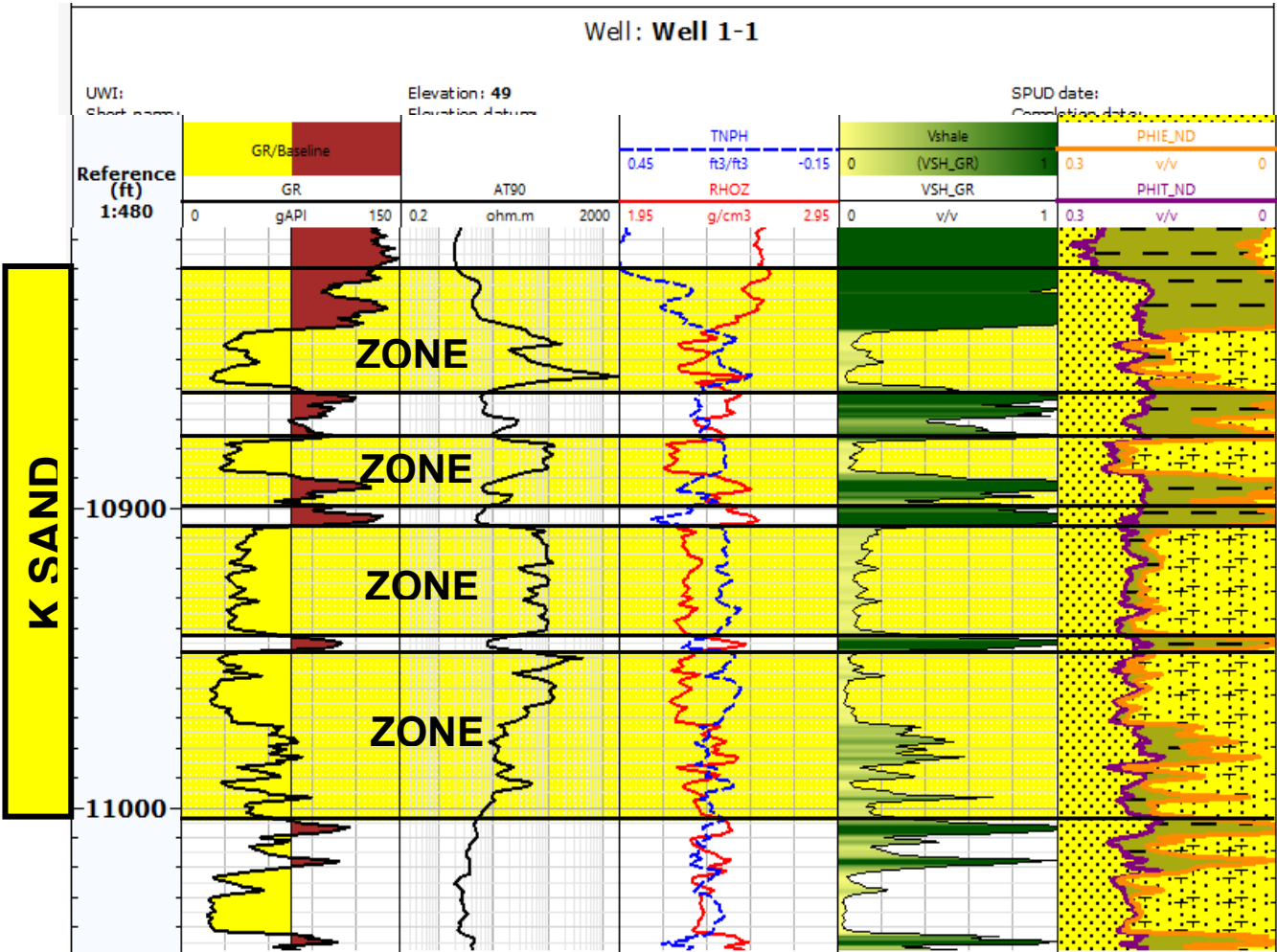


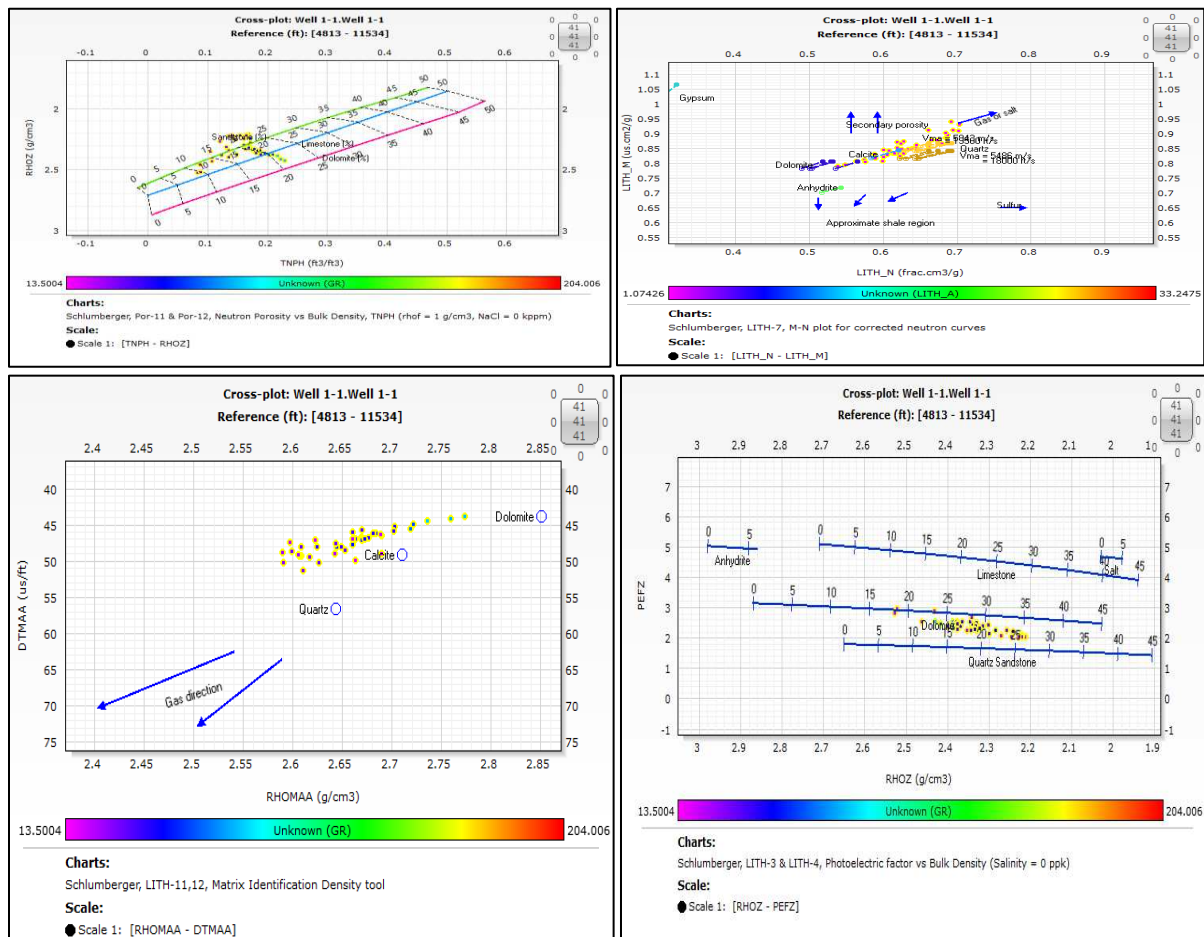
Figure 4.1: Composite wireline log showing K Sand reservoir in Well 1-1.

The composite wireline log of Well 1-1 (Fig. 4.1) reveals a thick sandstone interval designated as the K Sand reservoir. The reservoir extends from 10,840 ft to 11,005 ft, giving a gross thickness of 165 ft, while the cumulative net sandstone thickness is 135 ft, indicating a high proportion of clean reservoir sand.

The gamma-ray log is characterized by consistently low readings throughout the K Sand interval, reflecting low shale content and confirming sandstone dominance. Thin shale breaks separate the reservoir into four individual flow units (Zones I–IV), indicating cyclic sedimentation during delta progradation. The resistivity log exhibits relatively high responses across the sandstone intervals, suggesting hydrocarbon saturation. Density and neutron logs display characteristic sandstone responses with limited separation, further confirming the predominance of clean quartz-rich sandstone.

The multiple sandstone packages separated by thin shale layers indicates repeated depositional cycles associated with distributary channel migration and abandonment. Such vertical heterogeneity is typical of delta-front depositional systems within the Agbada Formation (Khan, 2025; Nwankwo, 2021).

4.2 Interpretation of Zone I



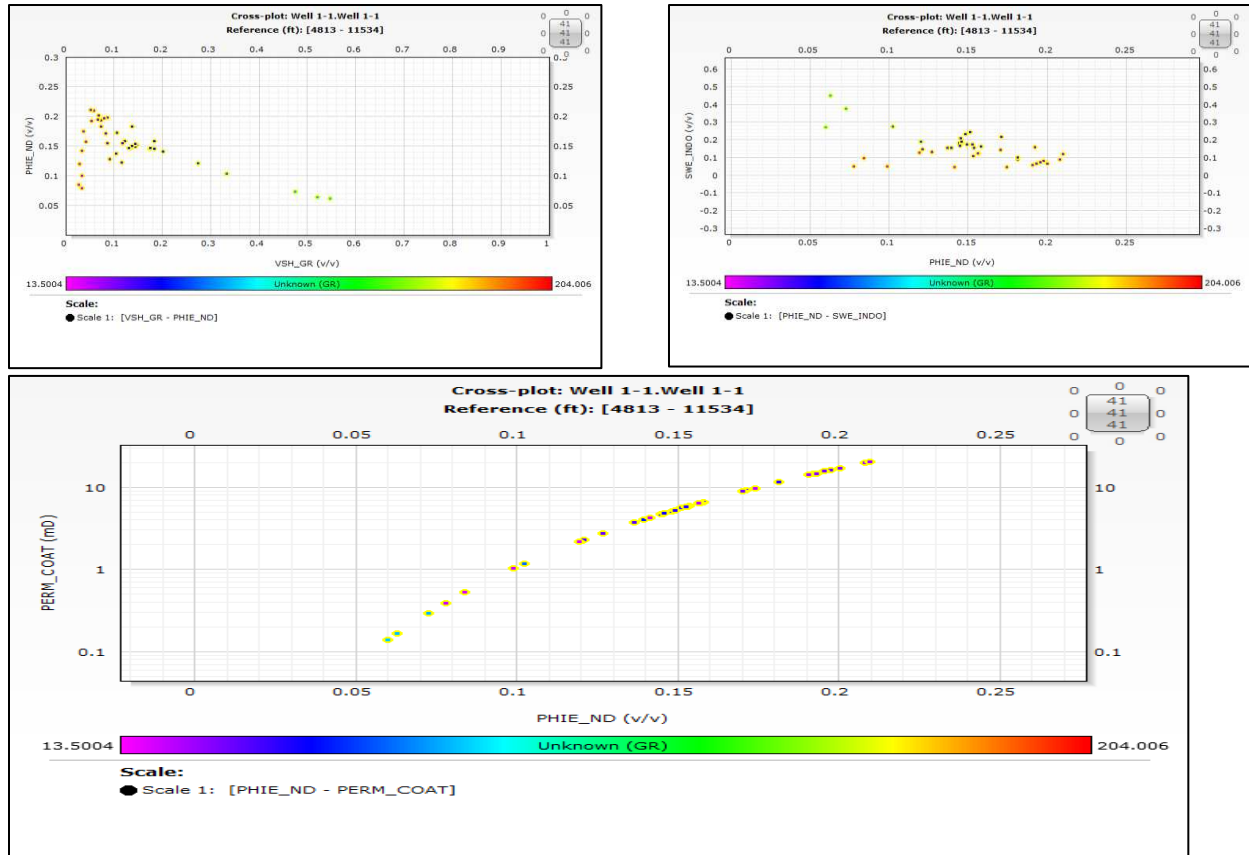


Figure 4.2: Density–Neutron, (b) M–N, (c) Matrix Identification (MID), (d) PEF–Density, (e) PHIE–Vsh (f) Sw–PHIE (g) Permeability–Porosity cross-plot for Zone I

The Density–Neutron cross-plot Fig. 4.2a indicates that the majority of data points cluster within the quartz sandstone field. Minimal divergence between density and neutron responses indicates negligible gas effects and confirms that the interval consists predominantly of clean sandstone with limited clay contamination (Al-Aani, 2024; Duranni 2015). The relatively tight clustering of data points suggests good sorting and uniform grain composition, characteristics commonly associated with high-energy distributary-channel deposits (Al-Aani, 2024).

The M–N cross-plot Fig. 4.2b further confirms quartz as the dominant framework mineral. The concentration of plotted points around the quartz endpoint indicates minimal contributions from calcite or dolomite, demonstrating that the reservoir matrix is mineralogically homogeneous (Al-Aani, 2024; Fajana, 2025). Quartz-rich sandstones generally preserve primary intergranular porosity during burial, making them favourable hydrocarbon reservoirs. The Matrix Identification plot Fig. 4.2c supports the interpretation obtained from the Density–Neutron and M–N plots. Most data occupy the quartz sandstone field, indicating little diagenetic alteration and confirming that reservoir quality is primarily controlled by depositional processes rather than mineral replacement.

Photoelectric Factor (PEF) Fig. 4.2d values remain consistent with quartz-rich sandstone. The absence of elevated PEF values associated with carbonate minerals confirms that the reservoir is dominated by siliciclastic sediments. This conforms with the regional depositional setting of the

Agbada Formation. The PHIE–Vsh relationship exhibits a clear inverse correlation. Effective porosity decreases progressively with increasing shale volume because clay minerals occupy pore spaces and reduce interconnected pore networks as shown in (Fig. 4.2e). Zone I records an average effective porosity of approximately 15% and a shale volume of 14%, indicating a relatively clean reservoir possessing moderate storage capacity. The Sw–PHIE plot From Fig. 4.2f demonstrates that intervals with higher effective porosity generally possess lower water saturation, implying efficient hydrocarbon displacement of formation water. Average water saturation of approximately 15% indicates significant hydrocarbon saturation within the reservoir (Al-Aani, 2024; Duranni 2015). The general cross-plots showed that Zone I represents a moderately good-quality distributary-channel sandstone capable of commercial hydrocarbon production.

4.3 Interpretation of Zone II

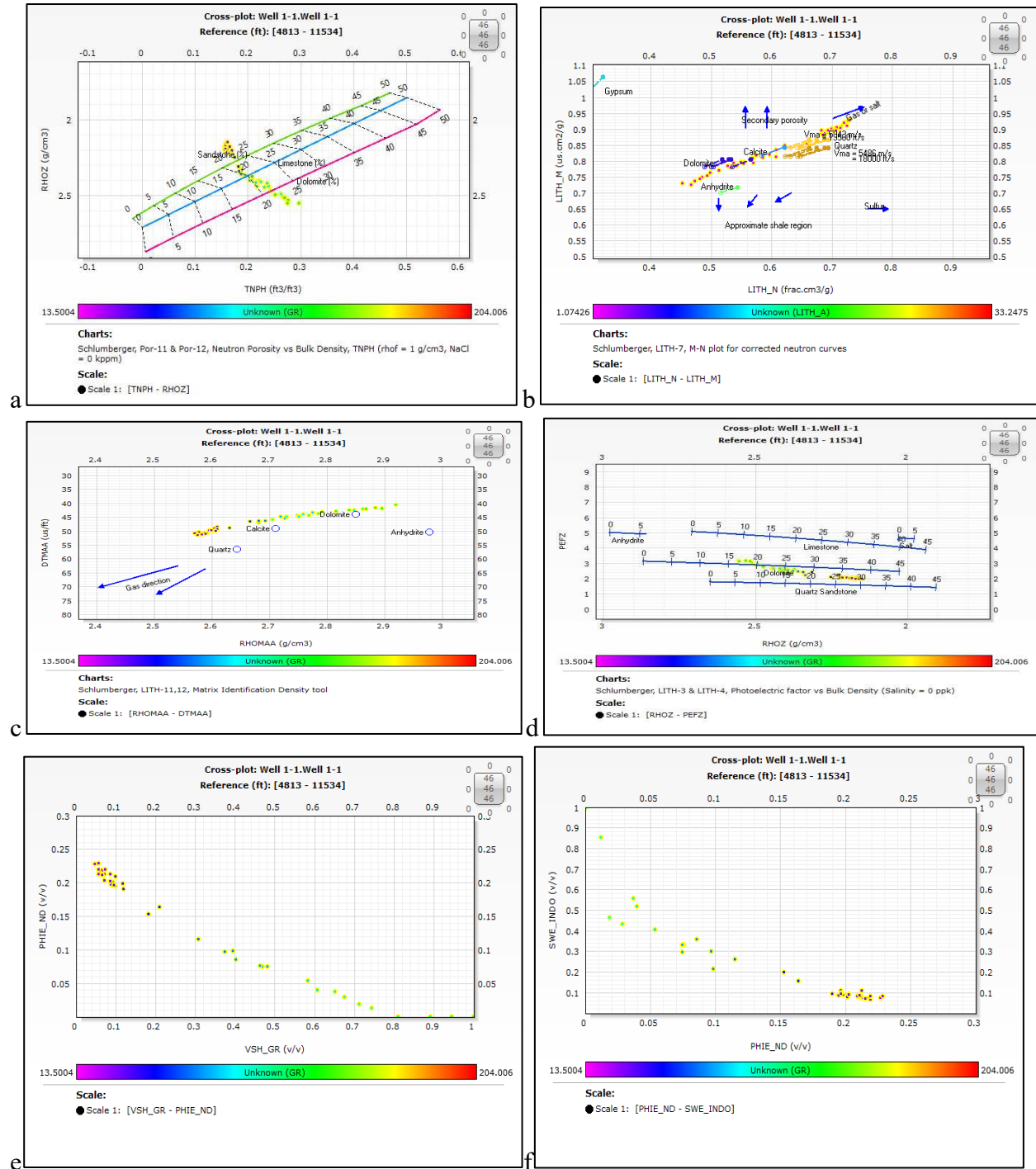
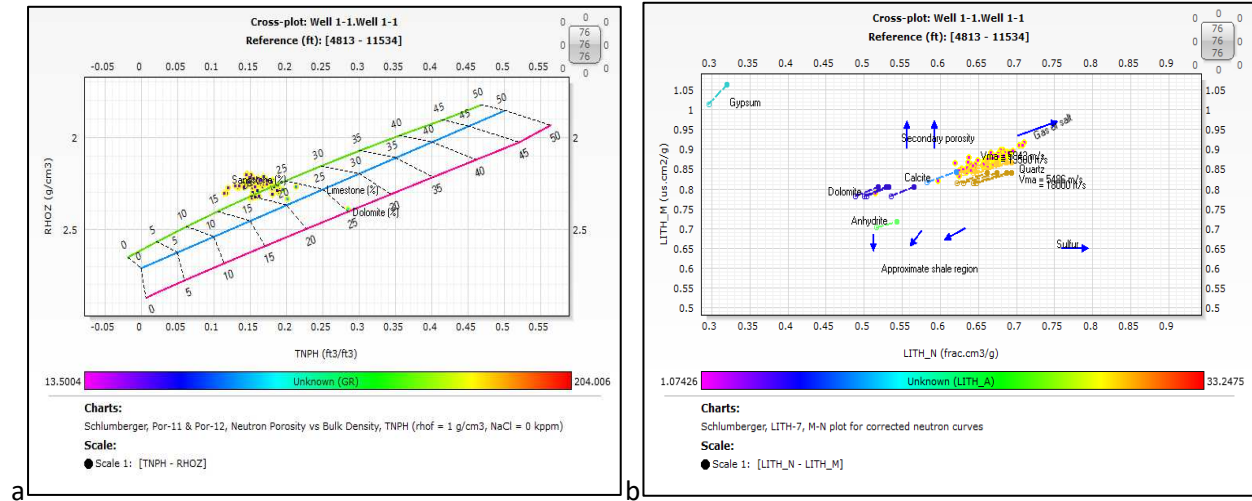


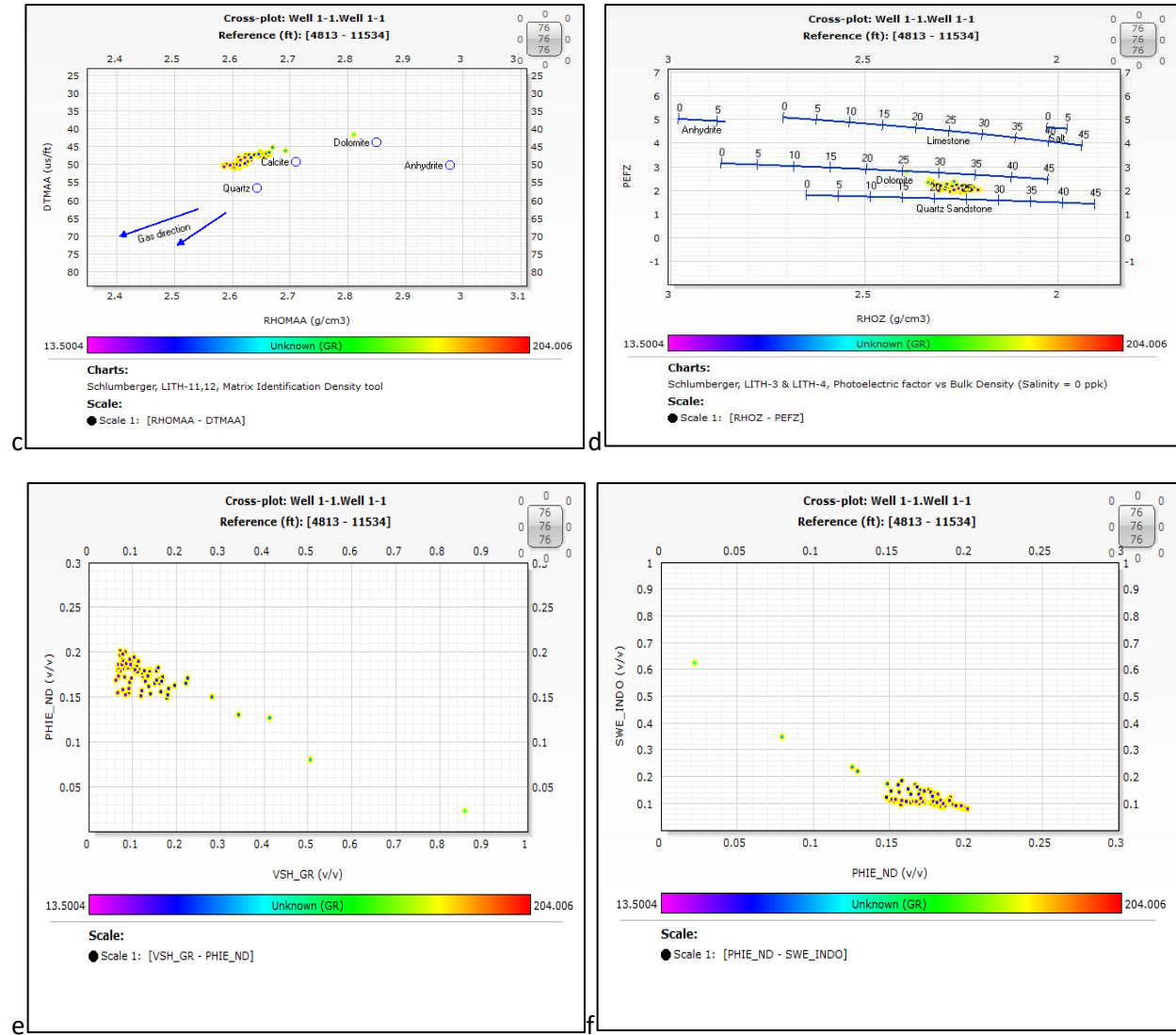
Figure 4.3: (a) Density–Neutron (b) M–N (c) Matrix Identification plot. (d) PEF–Density (e) PHIE–Vsh cross for Zone II. (f) Sw–PHIE.

Compared with Zone I, the Density–Neutron plot (Fig. 4.3a) exhibits slightly greater scatter, reflecting increased shale influence within the reservoir interval. The broader distribution of points suggests poorer grain sorting and greater mineralogical heterogeneity (Al-Aani, 2024). Although, quartz remains the dominant mineral, (Fig. 4.3b) slight deviation toward the shale trend indicates

increased clay content. This interpretation is consistent with deposition under relatively lower-energy conditions than those responsible for Zone I. The MID plot (Fig. 4.3c) demonstrates increased mineralogical variability compared with Zone I. Clay minerals reduce pore connectivity and contribute to deterioration of reservoir quality. The PEF (Fig 4.3d) response confirms increased clay mineral content while maintaining a siliciclastic composition. The interval remains sandstone dominated but exhibits appreciably greater heterogeneity. The inverse relationship between effective porosity and shale volume fig. 4.3e becomes more pronounced in Zone II. Average shale volume increases to 40%, while effective porosity decreases to approximately 12%. This substantial increase in shale content significantly reduces storage capacity. Water saturation (Fig 4.3f) increases to approximately 37%, indicating reduced hydrocarbon saturation compared with Zone I while permeability (Fig. 4.6g) averages approximately 9.67 mD. This higher shale volume introduces greater heterogeneity and increases uncertainty in fluid flow behaviour. The higher water saturation is attributed to increased clay content and reduced pore connectivity. From the cross-plots, Zone II represents a lower-quality reservoir deposited under relatively quieter depositional conditions, possibly corresponding to an interdistributary bay or distal mouth-bar environment.

4.4 Interpretation of Zone III



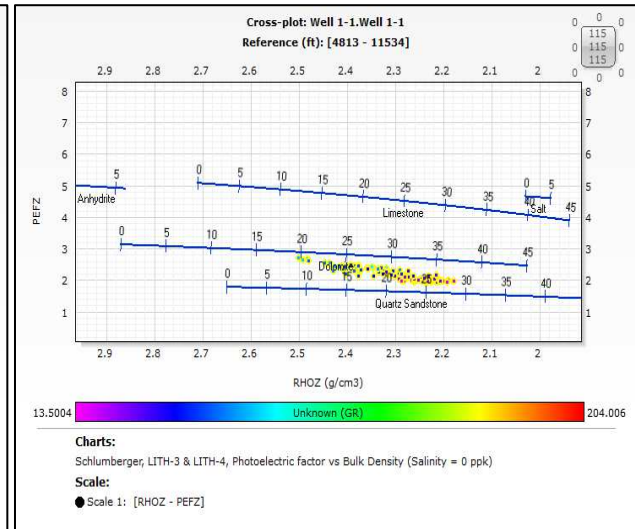
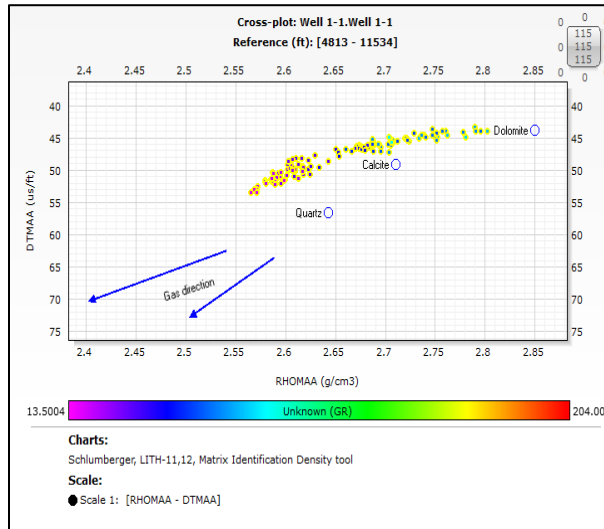
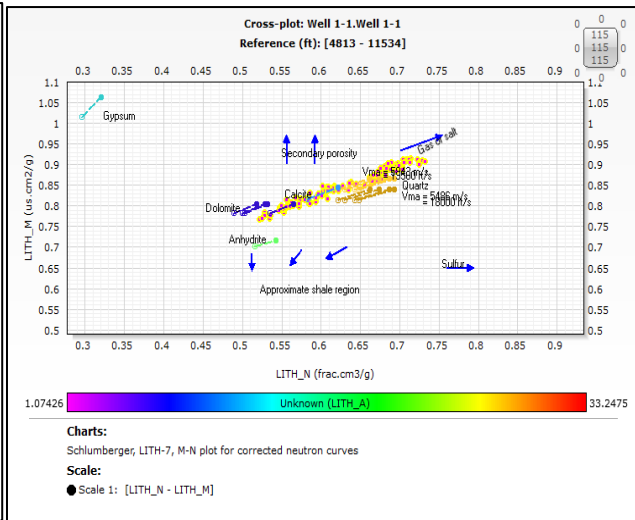
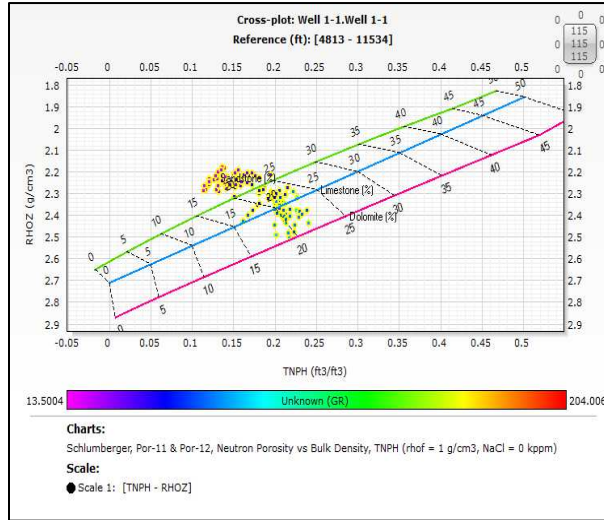


Figures 4.4 (a)Density–Neutron cross-plot, (b) M–N, MID, (c) PEF–Density, (d) PHIE–Vsh, (e) Sw–PHIE and (f) Permeability–PHIE plots for Zone III.

Zone III exhibits the tightest clustering of Density–Neutron data (Fig. 4.4a) within the quartz sandstone field, indicating an exceptionally clean and well-sorted sandstone. The limited scatter reflects remarkable lithological uniformity (Al-Aani, 2024; Duranni 2015). All cross-plots (Fig. 4.4a – Fig. 4.4f) consistently identify Zone III as the highest-quality reservoir interval within Well 1-1. The average shale volume decreases to 13%, while effective porosity increases to 17%, representing the highest porosity recorded in the well. Water saturation declines to approximately 12%, indicating a high hydrocarbon saturation, and permeability increases to 9.75 mD, reflecting excellent pore connectivity and favorable fluid-flow characteristics.

These petrophysical characteristics suggest deposition within a high-energy distributary-channel environment, where sustained sediment transport produced well-sorted quartz-rich sandstone with minimal clay contamination (Al-Aani, 2024; Duranni 2015; Chuku & Umoh 2023). Consequently, Zone III constitutes the primary production target within Well 1-1.

4.5 Interpretation of Zone IV



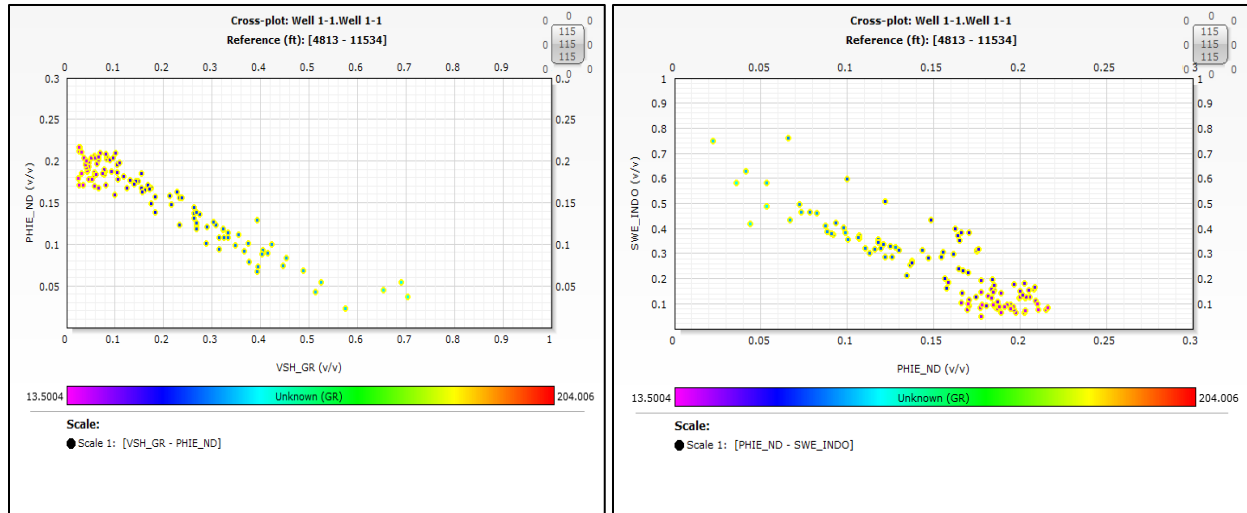


Fig. 4.5: (a) Density–Neutron (b) M–N (c) Matrix Identification plot. (d) PEF–Density (e) PHIE–Vsh cross for Zone IV. (f) Sw–PHIE (g) Permeability–Porosity cross-plot for Zone IV.

Zone IV (Fig. 4.5a – 4.5g) remains sandstone dominated but displays slightly greater heterogeneity than Zone III. The average shale volume increases to 20%, effective porosity decreases marginally to 15%, and water saturation rises to 26%, indicating a moderate reduction in hydrocarbon saturation. Average permeability is 8.35 mD, suggesting that the interval retains adequate pore connectivity for commercial production (Al-Aani, 2024; Mode et al., 2017). The combined cross-plot responses indicate that Zone IV was deposited under moderately energetic conditions, likely representing a transition from distributary-channel to mouth-bar deposits (Mode et al., 2017). Although reservoir quality is lower than in Zone III, the interval remains a viable hydrocarbon-producing unit and can contribute significantly to cumulative field production.

4.6 Integrated Reservoir Evaluation of Well 1-1

Table 1 Petrophysical Parameters for Well 1-1

Name	Reservoir	Zone	Top (ft)	Base (ft)	Gross (ft)	Av. N/G (v/v)	Av. Vsh (v/v)	Av. Øe (v/v)	Av. Sw (v/v)	Av. K (mD)
Well 1-1	K Sand	I	10840	10860	20	0.86	0.14	0.15	0.15	6.85
		II	10877	10898	21	0.60	0.40	0.12	0.37	9.67
		III	10907	10943	36	0.87	0.13	0.17	0.12	9.75
		IV	10947	11005	58	0.80	0.20	0.15	0.26	8.35
	L Sand	I	-	-	-	-	-	-	-	-
		II	-	-	-	-	-	-	-	-
		III	-	-	-	-	-	-	-	-
Average						0.78	0.22	0.15	0.23	8.66

The integrated petrophysical analysis of Well 1-1 (Table 1) indicates that the K Sand reservoir has an average net-to-gross ratio of 0.78 and an average shale volume of 0.22, an effective porosity of 15%, a water saturation of 23%, and a permeability of 8.66 mD. Together these petrophysical

parameters indicate a reservoir of moderate to good quality, with an adequate capacity to store hydrocarbons, and a good fluid flow.

The four identified reservoir zones (I to IV) all exhibit generally good reservoir characteristics, but of particular interest is the relatively low shale volume, high porosity, low water saturation, and high permeability of the Zone III which represents the most prospective for hydrocarbon production. On the other hand, Zone II has the largest volume of shale and water saturation and consequently, relatively poor reservoir quality and lower production potential. Zones I and IV have intermediate petrophysical properties and are considered to be secondary producing zones.

4.6 RESULTS AND INTERPRETATION OF WELL 2-1

Well 2-1 was interpreted using the same integrated workflow comprising reservoir delineation, lithofacies classification through cross-plots, petrophysical evaluation, and geological interpretation.

Unlike Well 1-1, Well 2-1 exhibits significantly thicker reservoir sands, lower shale content, higher porosity and permeability, and lower water saturation, suggesting that this well penetrates the central portion of the reservoir fairway where depositional conditions favored the accumulation of thick, clean distributary channel sandstones.

Reservoir Architecture of Well 2-1

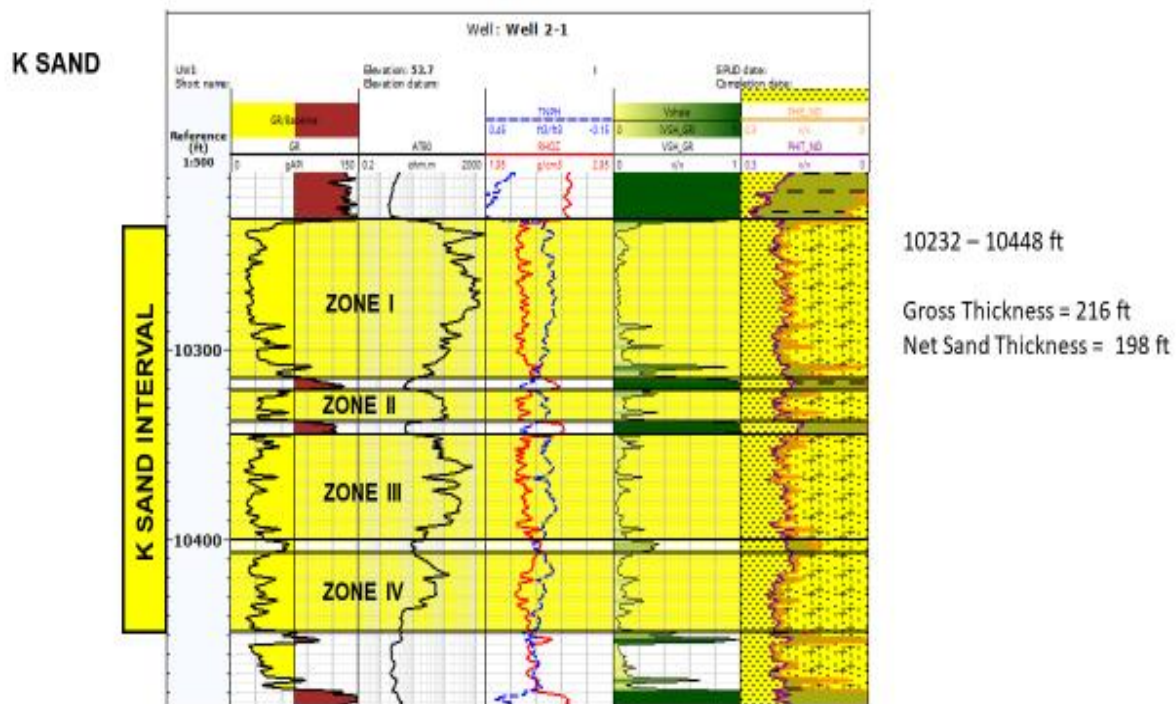


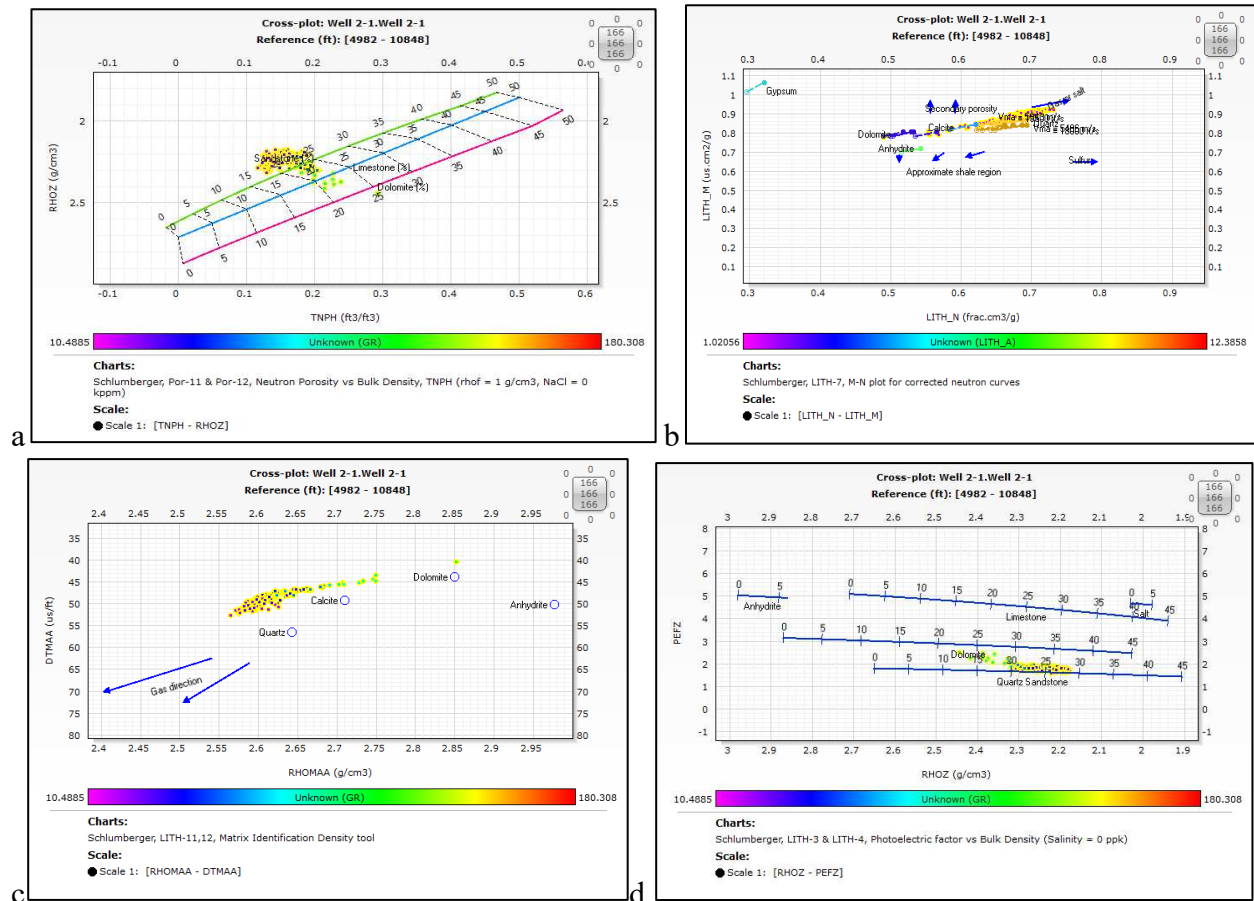
Fig 4.6: Composite wireline log showing the K Sand reservoir interval in Well 2-1.

The composite wireline log in Fig. 4.6 indicates a gross reservoir thickness of 216 ft and a net sandstone thickness of 198 ft for the K Sand between 10,232 ft and 10,448 ft. This net sand thickness is about 63 ft greater than the net sand thickness of the Well 1-1 and suggests that this part of the field is better developed as a reservoir.

Log Gamma Ray values are very low in the reservoir interval, consistent throughout, indicating very little shale content and sandstone being the dominant lithology. The relative high resistivity values are retained throughout all four zones of the reservoir, and this is interpreted as a high hydrocarbon saturation. The density and neutron logs indicate responses typical of clean sandstone, with a small amount of crossover, and thin shale layers divide the reservoir into four flow units separated hydrodynamically (Zones I to IV).

4.7 Interpretation of Zone I

Zone I extends from 10,232 ft to 10,315 ft, giving a thickness of 83 ft, making it the thickest individual reservoir unit encountered in either well. This thickness alone suggests prolonged deposition under stable, high-energy sedimentary conditions.



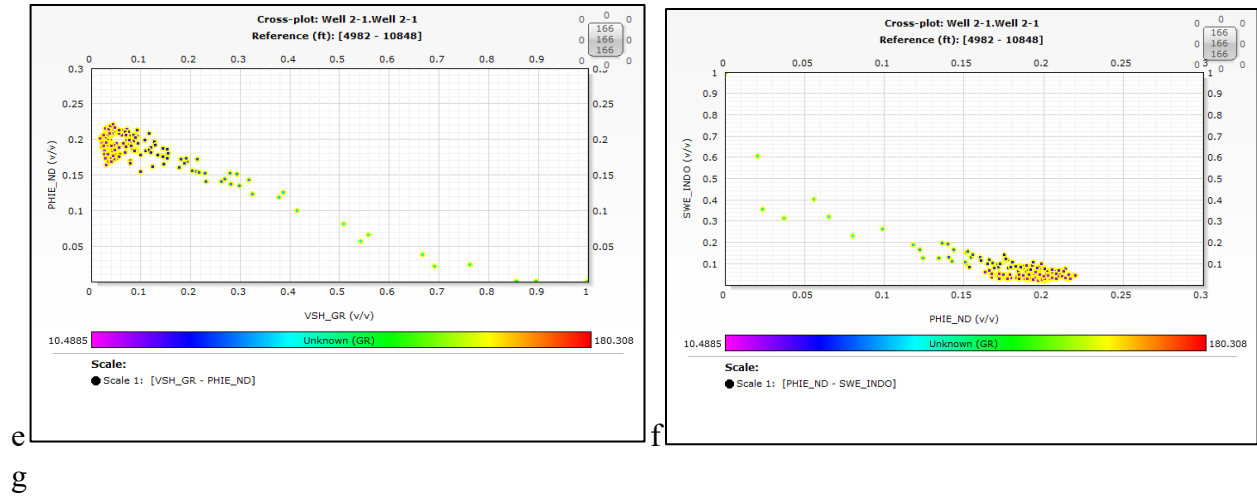


Fig. 4.7: Density–Neutron (b) M–N Cross Plot (c) Matrix Identification (MID) Plot. (d) PEF–Density Cross Plot (e) PHIE–Vsh Cross Plot (f) Sw–PHIE Cross Plot

The Density–Neutron cross-plot (Fig 4.7a) shows a very tight clustering of data within the quartz sandstone field. Unlike Well 1-1, almost no data migrate toward the shale trend, indicating that the interval contains exceptionally clean sandstone with negligible clay contamination. The absence of neutron-density crossover caused by gas effects further suggests that the reservoir contains predominantly oil-bearing sandstone (Okpala et al., 2021; Onuoha, 2022). The limited scatter demonstrates remarkable lithological uniformity, indicating that the sandstone experienced minimal post-depositional alteration. The M–N plot Fig. 4.7b confirms quartz as the dominant mineral. Nearly all data points occupy the quartz endpoint, while very few points deviate toward carbonate or shale trends. This mineralogical homogeneity indicates that the depositional environment was dominated by mature siliciclastic sediments transported over considerable distances before deposition. Such mature quartz-rich sandstones typically preserve primary intergranular porosity during burial, making them excellent hydrocarbon reservoirs.

The MID plot (Fig. 4.7c) confirms that matrix mineralogy is dominated by quartz with little evidence of significant carbonate cementation. This observation implies that reservoir quality is controlled primarily by depositional sorting rather than diagenetic modification. The Photoelectric Factor (Fig. 4.7d) remains consistently within the quartz sandstone range. Low PEF values indicate that silica constitutes the dominant mineral phase while carbonate minerals are virtually absent. This interpretation conforms with the regional geology of the Agbada Formation. An inverse relationship exists between shale volume and effective porosity (Fig 4.7e-f). Zone I records: Average Effective Porosity of 18%, Average Shale Volume of 13%. The relatively low shale content allows excellent preservation of pore space. The porosity values are considerably higher than those obtained from Well 1-1, indicating improved reservoir storage capacity. The Sw–PHIE relationship indicates low irreducible water saturation. Average Sw is only 10%, demonstrating excellent hydrocarbon saturation according to Archie (1942). The low Sw confirms that pore spaces are predominantly occupied by hydrocarbons. Zone I represents an excellent quality distributary channel sandstone capable of sustaining high production rates.

4.8 Interpretation of Zone II

Zone II extends between 10,321 ft and 10,338 ft with a thickness of 17 ft.

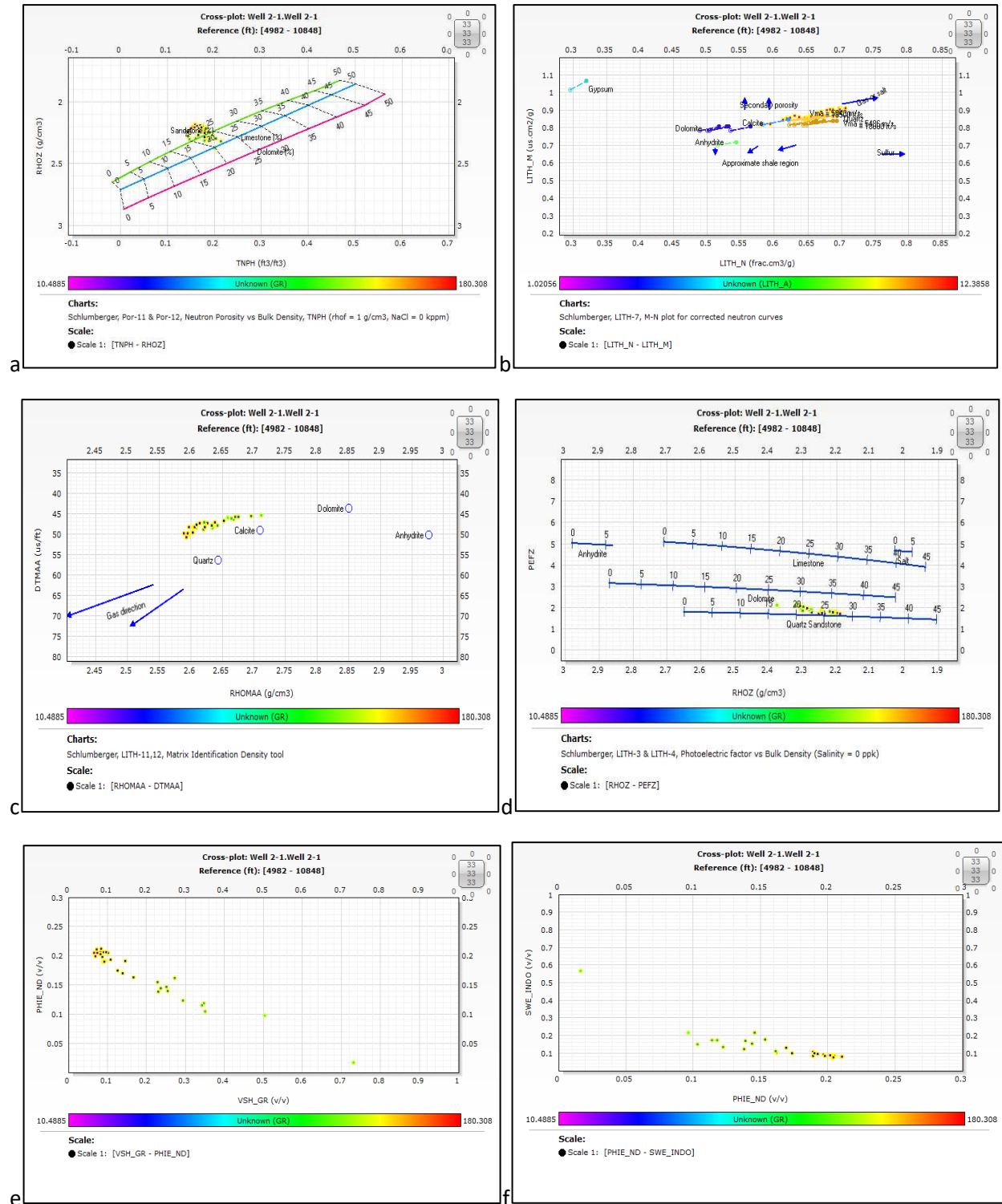


Fig. 4.8: (a)Density-Neutron, (b)M-N, (c)MID, (d)PEF-Density, (e)PHIE-Vsh, (f)Sw-PHIE

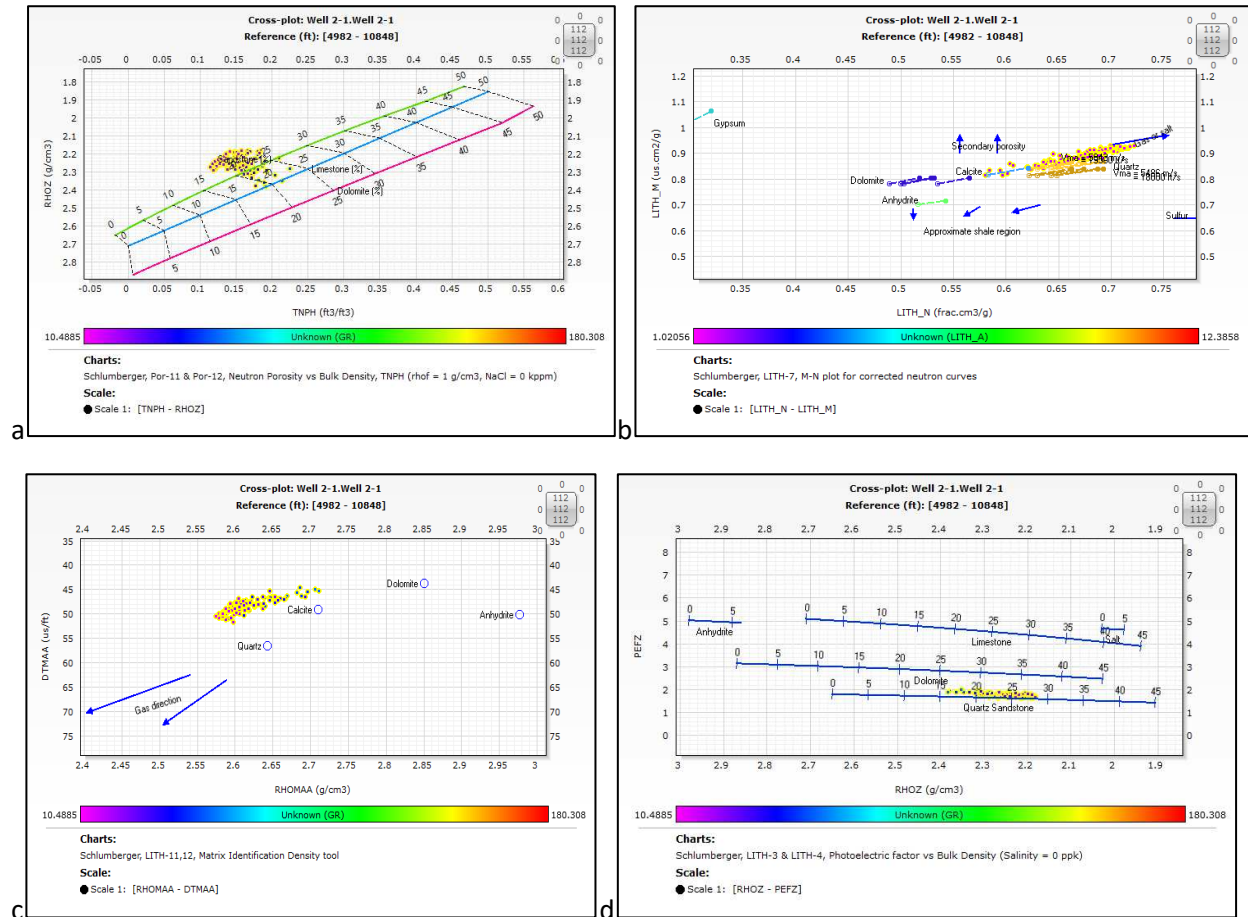
All cross-plots (Fig. 4.8a-f) consistently indicate that Zone II is composed predominantly of clean quartz sandstone with only minor shale influence. The average shale volume is 20%, while effective porosity remains relatively high at 16%. Water saturation averages 14%, indicating good hydrocarbon saturation, and permeability reaches 10.52 mD, reflecting favorable pore connectivity despite the thinner reservoir interval.

The depositional characteristics suggest accumulation within a distributary-mouth-bar environment where moderate-energy conditions produced a well-sorted sandstone body with limited clay intercalation (Buckley, 1991; Bjørlykke, 2014). Although thinner than the adjacent flow units, Zone II constitutes a productive reservoir capable of contributing to field development.

4.9 Interpretation of Zone III

Zone III extends between 10,345 ft and 10,401 ft, giving a gross thickness of 56 ft.

This interval represents one of the most laterally continuous sandstone bodies within the field.



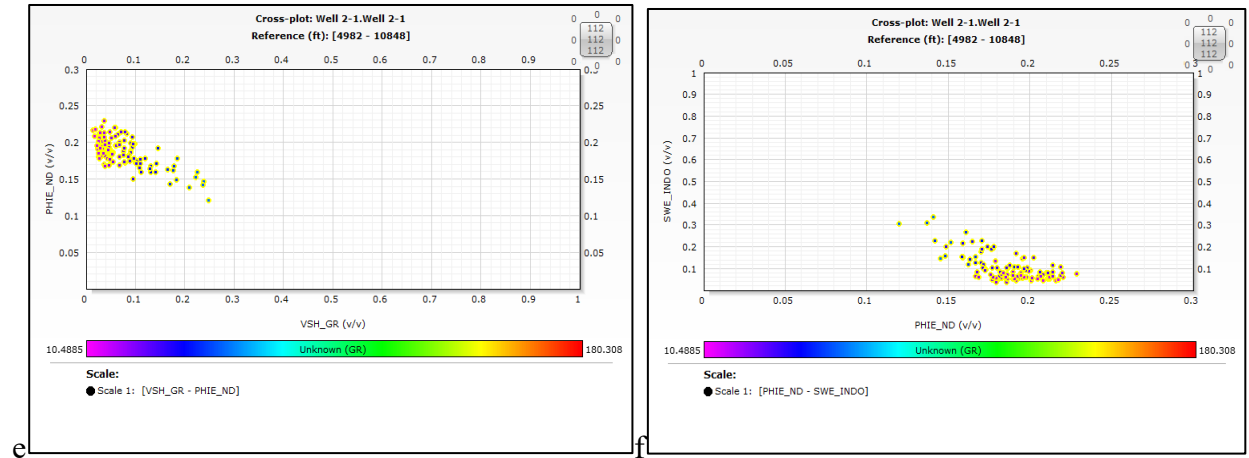


Fig. 4.9 (a).Den-Neu Plot; (b). M-N Plot;(c). M-N Plot; (d). Pefz-Den Plot; (e). Phie-Vsh Plot; (f). Sw-Phie Plot of K Sand Zone III in Well 2-1

Zone III consistently exhibits the best combination of lithological and petrophysical properties observed in Well 2-1 (Fig. 4.9a-f). Density–Neutron, M–N, MID, and PEF–Density plots confirm a clean quartz-rich sandstone with minimal clay contamination. The average shale volume decreases to 8%, the lowest recorded within the study area, while effective porosity reaches 18% and water saturation declines to 10%, indicating excellent hydrocarbon saturation. Permeability increases to 13.00 mD, reflecting outstanding pore connectivity and flow efficiency.

The uniformity of the cross-plot responses suggests deposition within the axis of a high-energy distributary channel where sustained sediment transport produced exceptionally well-sorted sandstone with minimal shale input (Al-Aani, 2024). From a reservoir petrophysics, Zone III constitutes the principal hydrocarbon-bearing interval in the “Nanya” Field and should be prioritized for production and future infill drilling.

4.10 Interpretation of Zone IV

Zone IV occurs between 10,406 ft and 10,448 ft, with a thickness of 42 ft.

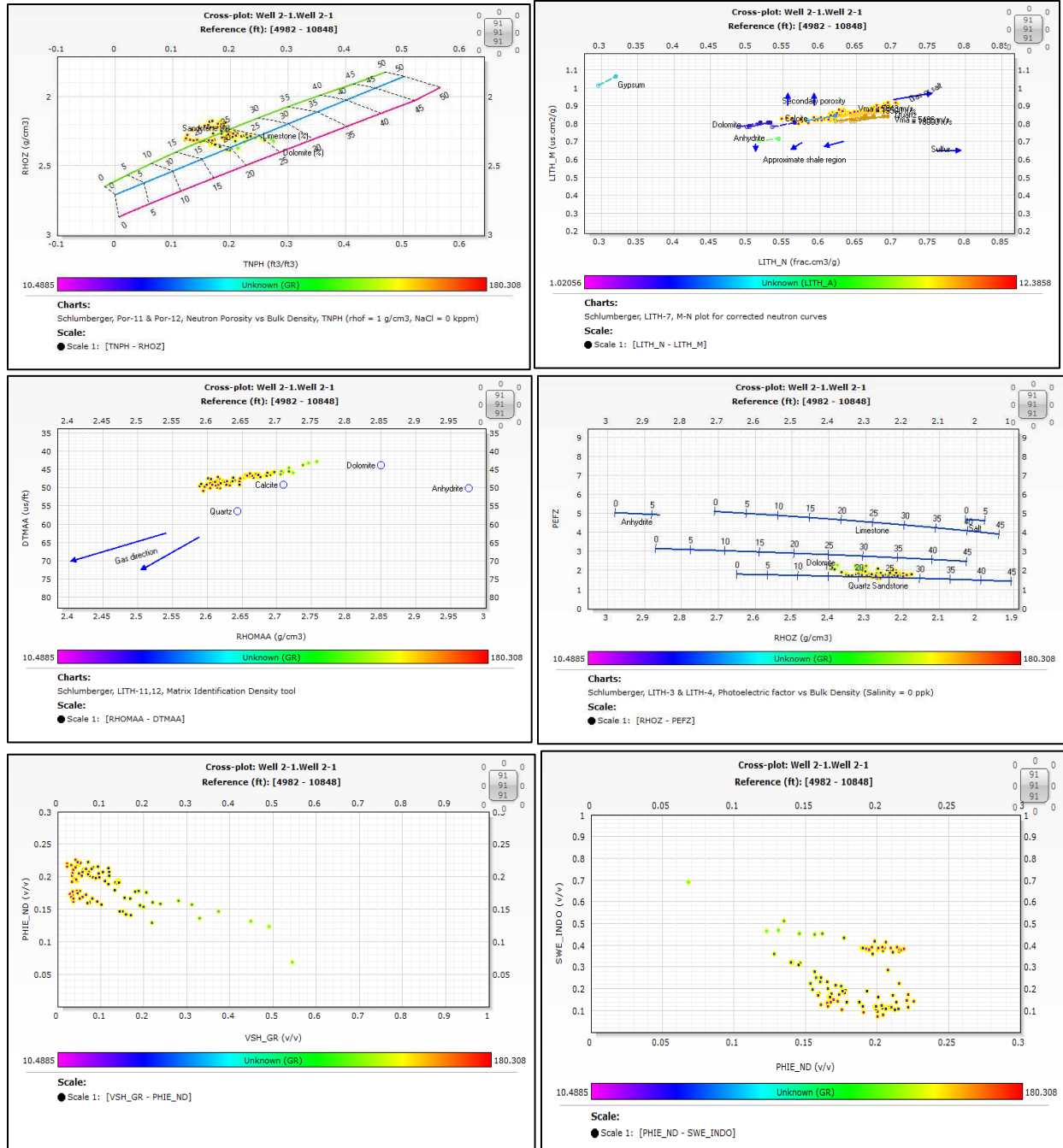


Fig. 4.10 (a).Den-Neu Plot; (b). M-N Plot;(c). M-N Plot; (d). Pefz-Den Plot; (e). Phie-Vsh Plot; (f). Sw-Phie Plot of K Sand Zone IV in Well 2-1

Cross-plot analysis above indicates that Zone IV remains dominated by clean quartz sandstone with only slight increases in shale content relative to Zone III. The average shale volume is 9%, while effective porosity reaches 19%, representing the highest porosity recorded within the Enah Field. Water saturation increases slightly to 23%, suggesting greater water occupancy of the pore spaces; however, permeability rises further to 14.19 mD, the highest value obtained from either

well. This combination indicates that the interval retains excellent flow capacity despite the modest increase in water saturation.

The depositional characteristics are consistent with thick, well-developed distributary-channel deposits that experienced excellent sorting and preservation of primary porosity. Zone IV therefore remains an attractive production target and is expected to contribute significantly to cumulative hydrocarbon recovery.

4.12 Integrated Reservoir Evaluation of Well 2-1

Table 2 Computed Petrophysical Parameters for Well 2-1

Name	Reservoir	Zone	Top (ft)	Base (ft)	Gross (ft)	Av. N/G (v/v)	Av. Vsh (v/v)	Av. Øe (v/v)	Av. Sw (v/v)	Av. K (mD)
Well 2-1	K Sand	I	10232	10315	83	0.87	0.13	0.18	0.10	12.49
		II	10321	10338	17	0.80	0.20	0.16	0.14	10.52
		III	10345	10401	56	0.92	0.08	0.18	0.10	13.00
		IV	10406	10448	42	0.91	0.09	0.19	0.23	14.19
	L Sand	I	-	-	-	-	-	-	-	-
		II	-	-	-	-	-	-	-	-
		III	-	-	-	-	-	-	-	-
Average						0.88	0.12	0.18	0.14	12.55

The integrated petrophysical evaluation in Table 2 indicates that Well 2-1 has the best reservoir quality found in the Enah Field. The net to gross ratio for the K Sand here is 0.88; shale content 0.12; effective porosity 18%; water saturation 14%; and permeability 12.55 mD. These figures suggest that the sandstone is clean, laterally continuous and has considerable hydrocarbon storage capacity and fluid motion (Buckley, 1991).

When the four zones are ranked by shale volume, effective porosity, water saturation, and permeability, then Zone III is the zone that has the greatest potential to produce. The water saturation is slightly higher than the other zones, but the reservoir quality in zone IV is excellent, probably because of good effective porosity and permeability. The thickest net reservoir interval is in Zone I and has good petrophysical properties, with Zone II having good reservoir properties, albeit a relatively thin sandstone interval.

4.13 Integrated Lithofacies Analysis and Depositional Environment

Lithofacies interpretation helps to define spatial distribution of rock types, depositional environments, and reservoir heterogeneity (Lake, 1989). In this study, lithofacies classification was achieved through the integrated interpretation of Density–Neutron, M–N, Matrix Identification (MID), Photoelectric Factor–Density (PEF–DEN), PHIE–Vsh, Sw–PHIE and Permeability–PHIE cross-plots generated for each reservoir unit in Wells 1-1 and 2-1.

The integrated cross-plot analysis (Fig. 4.11) consistently indicates that the K Sand reservoir is dominated by mature quartz-rich sandstone with subordinate shaly sandstone intervals. The

clustering of most data points within the quartz field on the Density–Neutron, M–N and MID plots indicates that the reservoir consists predominantly of clean siliciclastic sediments with little evidence of carbonate cementation or significant mineralogical alteration (Mode, et al., 2017; Al-Aani, 2024). The PEF–Density plots further support this interpretation by exhibiting low photoelectric factor values characteristic of quartz sandstones.

The vertical variation in lithofacies reflects repeated episodes of deltaic sedimentation, during which distributary channels, mouth bars and interdistributary bays migrated across the study area (Bridge, 2003; Bjørlykke, 2014; Miall, 2016). These implies that the reservoir architecture comprises of stacked sandstone bodies separated by thin marine shale layers that act as intra-reservoir barriers while maintaining overall reservoir continuity.

The dominant lithofacies recognized in the study area are;

(i) Clean Quartz Sandstone Facies

This facies is characterized by low gamma-ray response, low shale volume (generally <15%), high effective porosity, high permeability, low water saturation, tight clustering on Density–Neutron and M–N plots.

The facies represents high-energy distributary-channel deposits where continuous sediment transport removed fine-grained materials, resulting in well-sorted sandstone with excellent reservoir quality. This facies dominates Zones I, III and IV of Well 2-1 and Zone III of Well 1-1.

(ii) Shaly Sandstone Facies

This facies is characterized by moderate gamma-ray response, increased shale volume, reduced effective porosity, moderate permeability and higher water saturation.

The facies reflects deposition within lower-energy mouth-bar or interdistributary environments where clay minerals accumulated together with sandstone. Zone II of Well 1-1 exhibits the strongest expression of this lithofacies.

(iii) Thin Marine Shale Facies

Thin shale beds separating the reservoir units indicate periods of reduced sediment supply and increased marine flooding. Although these shale intervals are relatively thin, they serve as important flow barriers that divide the K Sand reservoir into four hydraulically distinct flow units.

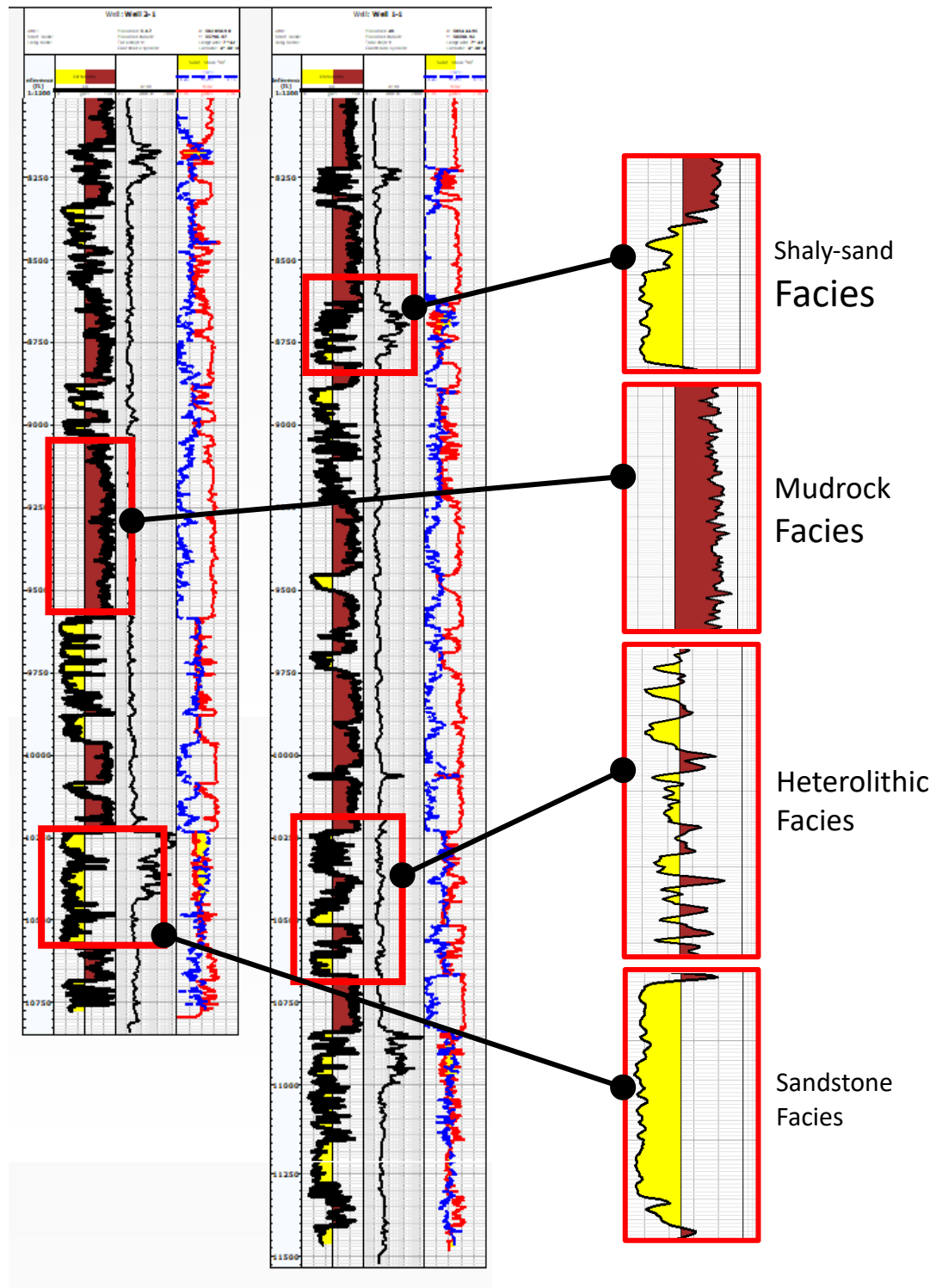


Fig. 4.11 Integrated lithofacies analysis

The integrated lithofacies succession indicates that the Nanya's Field developed within a prograding delta-front setting dominated by distributary channels and mouth bars. This could be attributed to thick stacked sandstone bodies, excellent vertical reservoir continuity, low shale volume in most reservoir units, predominance of quartz-rich sandstone, repeated fining-upward depositional cycles with thin marine flooding shales separating sandstone packages (Igili et al., 2026; Khan et al., 2025).. These are characteristics features consistent with deposition within the paralic Agbada Formation of the Niger Delta (Short & Stauble, 1967; Stacher, 1995).

4.14 Comparative Petrophysical Analysis of Wells 1-1 And 2-1

To establish the most representative reservoir quality within Nanya's Field, the computed petrophysical parameters from both wells were compared.

Table 3: Comparison of average petrophysical properties of Wells 1-1 and 2-1.

Parameter	Well 1-1	Well 2-1
Gross Thickness (ft)	165	216
Net Sand (ft)	135	198
Average N/G	0.78	0.88
Average Vsh	0.22	0.12
Average PHIE	15%	18%
Average Sw	23%	14%
Average Permeability	8.66 mD	12.55 mD

The comparison demonstrates that Well 2-1 possesses significantly superior reservoir quality with greater gross thickness and net sandstone thickness indicating improved reservoir development and larger hydrocarbon storage capacity. Similarly, the higher net-to-gross ratio suggests greater lateral continuity of clean sandstone bodies. The shale volume decreases from 22% in Well 1-1 to only 12% in Well 2-1, indicating cleaner depositional conditions. Effective porosity increases by approximately 20%, while permeability increases by nearly 45%. Water saturation decreases considerably, suggesting improved hydrocarbon saturation. Analysis of the two wells indicate that Well 2-1 penetrates the central depositional axis of the distributary channel system where sediment sorting and reservoir preservation were most favorable.

4.15 RESERVOIR CORRELATION

Reservoir correlation is essential for establishing the spatial continuity of hydrocarbon-bearing units. Reservoir correlation between the two wells (Fig 4.12) suggests good lateral continuity of the K Sand reservoir; however, additional wells and seismic data are required to fully confirm field-wide continuity. The four reservoir flow units recognized in Well 1-1 can be confidently traced into Well 2-1 based on similar wireline log signatures and stratigraphic positions. Four laterally continuous sandstone bodies and consistent shale markers separating reservoir units with similar depositional stacking patterns. The stratigraphic correlation demonstrates that reservoir connectivity remains high throughout the field.

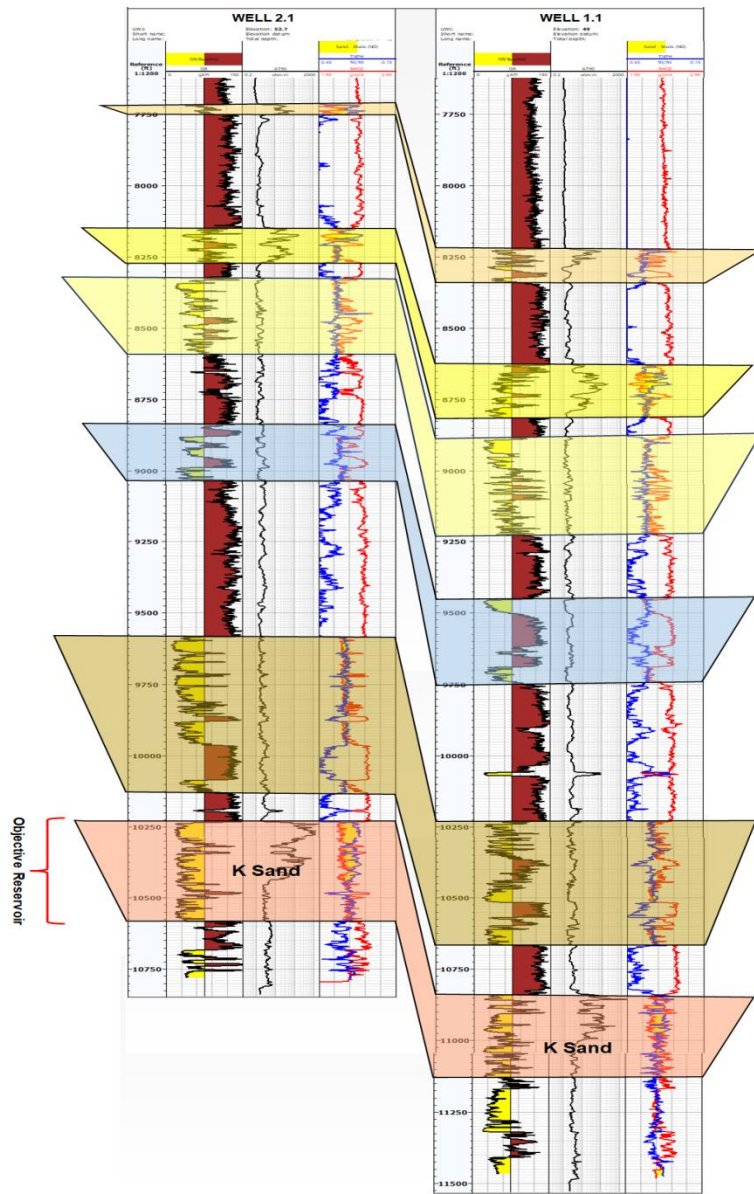


Fig. 4.12 Correlation of well 1-1 and 2-1

5. Conclusion

This study used a lithofacies and petrophysical evaluation to characterize the reservoir rocks of the K Sand in the Nanya field offshore the Niger Delta using wireline log data from wells 1-1 and 2-1. The K Sand was interpreted as the main reservoir, and the K Sand was subdivided into four flow units (KZones I, II, III, IV) using the intervening shale layers and unique log features. The crossplots of both the Density–Neutron and M–N indicated that the dominant reservoir lithofacies was quartz-rich sandstone, which was mostly found in ****Zone II****, supported by the Photoelectric Factor – Density (PEF – DEN) crossplots.

Petrophysics results indicate that Well 2-1 has better overall reservoir quality, with lower shale content and water saturation and higher net-to-gross ratio, effective porosity and permeability compared to Well 1-1. The wells are correlated, which implies a good lateral continuity of the flow units. Based on the favorable properties, Zone III appears to be the most promising hydrocarbon-bearing zone, with Zone IV being a secondary development zone.

The results support this, as lithofacies distribution is an important factor in controlling reservoir quality and heterogeneity within the field. This integrated approach provides a reliable reservoir characterization tool in areas of limited data and contributes to the overall understanding of the reservoir architecture, variation in reservoir quality, and hydrocarbon potential of the Agbada Formation. The results also provide an actual basis for the future appraisal, reservoir development planning and well placement decisions in the Nanya Field.

6. Recommendations

These results should be expanded to include seismic attribute analysis and seismic inversion for future work, to make more detailed prediction of reservoir properties possible. Sedimentological descriptions of core combined with the interpretation from wireline logs would also provide a better definition of depositional facies models. The integrated effort would help in improving the knowledge of reservoir characteristics, improve the predictive reservoir model and enable better extraction of hydrocarbons from Nanya Field reservoirs in the Niger Delta.

Data Availability: Data will be made available on reasonable request to the authors.

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