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Improving Water Saturation Estimation in a Low Resistivity Shaly Sand Reservoir Through Integrated Electrofacies, Rock Typing, Clay Mineral Analysis, and Saturation Height Modeling: NEAG-5 Field, Egypt

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Abstract

Accurate water saturation estimation remains one of the major challenges in low resistivity shaly sand reservoirs due to the combined effects of conductive clay minerals, reservoir heterogeneity, and complex pore systems. Conventional Archie based approaches commonly overestimate water saturation, leading to uncertainty in net pay determination, hydrocarbon volumetrics, and reservoir development planning. This study presents an integrated petrophysical workflow for the Middle Bahariya Formation in the NEAG-5 Field, Egypt, combining electrofacies based rock typing, quantitative mineralogical modeling, Low Resistivity Pay (LRP) correction, and rock type dependent Saturation Height Function (SHF) analysis. Core derived capillary pressure data, X-ray diffraction (XRD) measurements and wireline logs were integrated to characterize reservoir quality variations and quantify the impact of clay mineral distribution on saturation behavior. Four reservoir rock types were identified and used to develop facies dependent saturation models. The integrated workflow significantly improved water saturation estimation, enhanced net pay identification, and resulted in a substantial increase in hydrocarbons initially in place compared with conventional evaluation methods.

Keywords: Water saturation, low resistivity pay, rock typing, saturation height function, clay minerals, Middle Bahariya Formation

1. Introduction

Reliable water saturation estimation remains one of the most critical challenges in the evaluation of shaly sand reservoirs. The presence of conductive clay minerals, complex pore systems, laminated shale, and variable capillary pressure behavior often leads to significant uncertainty in hydrocarbon saturation calculations, reserve estimation, and field development planning (Archie 1942; Waxman and Smits 1968). Conventional Archie based

approaches frequently overestimate water saturation in such environments because they assume clean reservoir conditions and neglect the electrical contribution of clay minerals.

Shaly sand reservoirs constitute an important hydrocarbon resource in the Western Desert of Egypt(El Gazzar et al. 2016) .However, their evaluation remains challenging due to strong reservoir heterogeneity and the widespread occurrence of clay minerals that reduce formation resistivity and complicate fluid saturation interpretation. In many cases, potentially productive intervals are incorrectly classified as water bearing zones, resulting in underestimated net pay and conservative hydrocarbon volume calculations.

The Middle Bahariya Formation in the NEAG-5 Field, Abu Gharadig Basin, represents an ideal case study for addressing these challenges (Fig. 1). The reservoir is a shallow marine shaly sandstone system exhibiting extreme heterogeneity in porosity, permeability, facies architecture, and clay mineralogy. The combined effects of laminated and dispersed clays reduce formation resistivity and invalidate conventional Archie based water saturation estimates. Previous reservoir evaluations underestimated net pay and Stock Tank Oil Initially in Place (STOIP), leading to suboptimal development strategies and early water breakthrough during injection.

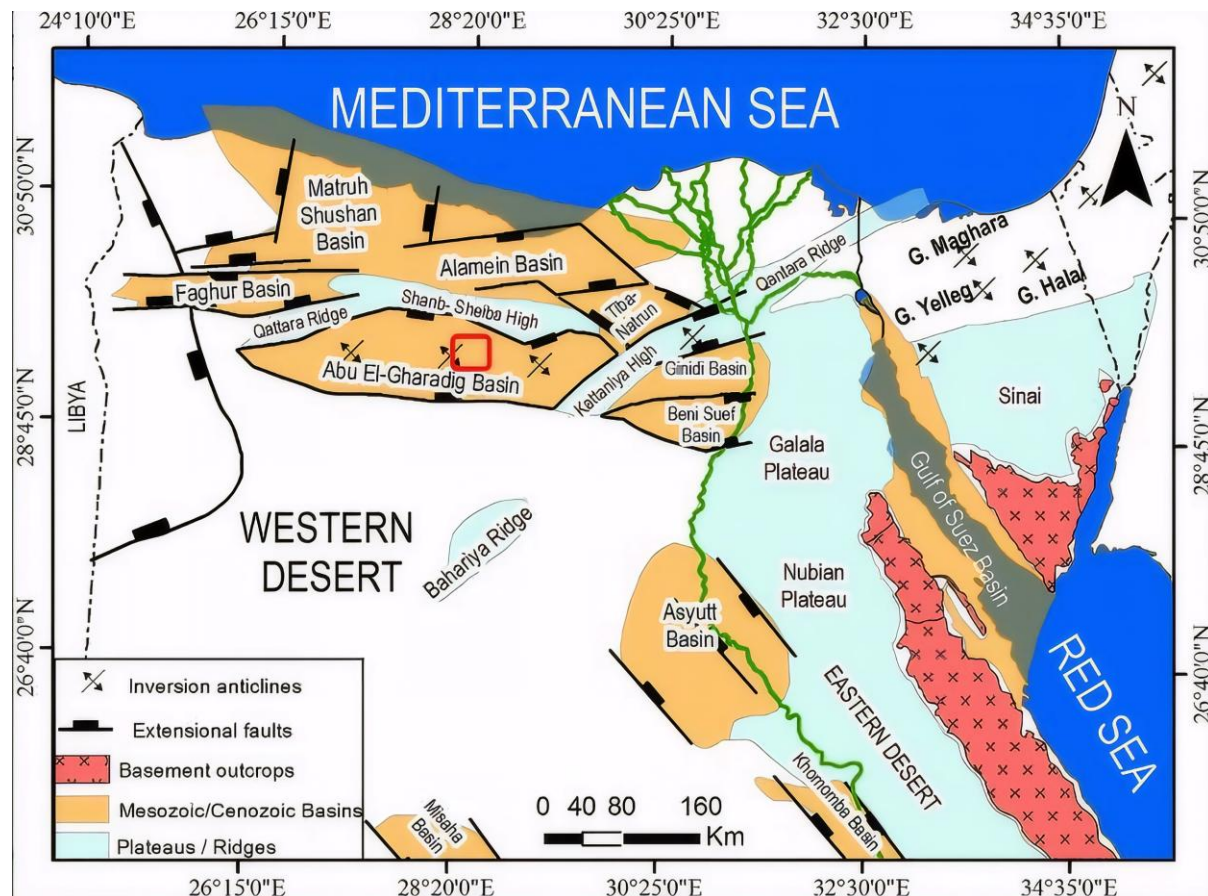


Fig. 1. Cenomanian basin in the Western Desert.(El Gazzar et al. 2016)

2. Geological Setting

The Abu Gharadig Basin forms part of a series of Mesozoic extensional basins that developed along the southern margin of the Neo Tethys Ocean during the breakup of Gondwana and subsequent rifting phases affecting northern Egypt. Basin development was controlled by multiple Jurassic and Early Cretaceous extensional episodes followed by Late Cretaceous inversion associated with the Syrian Arc tectonic event, resulting in the formation of fault bounded structural highs and inversion anticlines that constitute the principal hydrocarbon traps within the basin. The stratigraphic succession of the Abu Gharadig Basin extends from Paleozoic to Recent sediments and comprises alternating siliciclastic and carbonate depositional systems (Fig. 2).

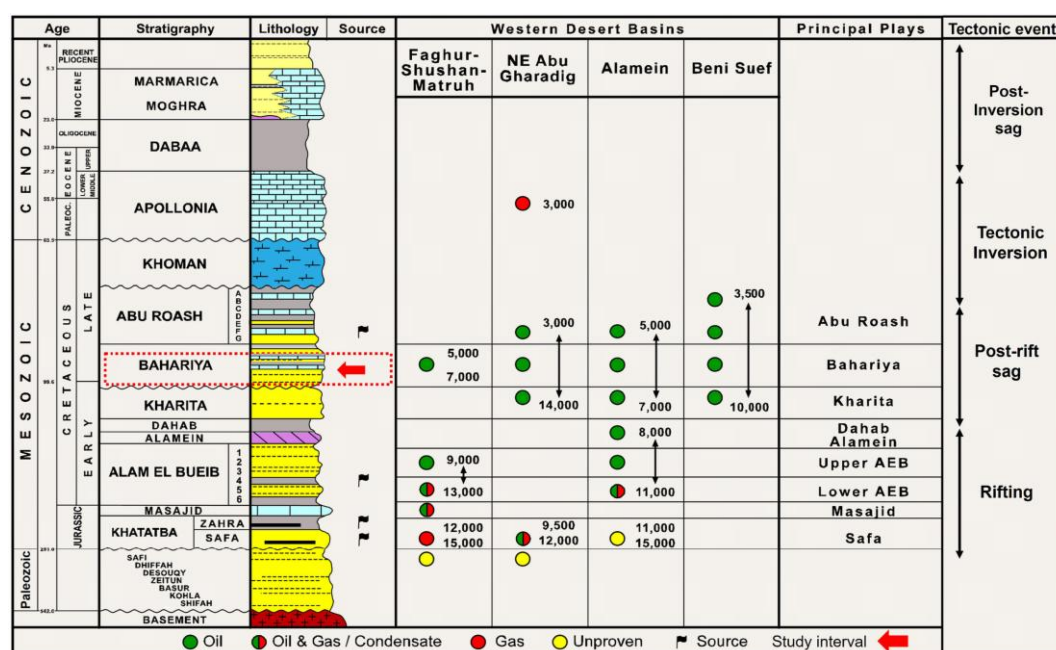


Fig. 2. Generalized stratigraphic sequence of the northern Western Desert, showing reservoir, seal, and source intervals, and principal tectonic episodes (Abdel-Fattah 2015)

3. Data and Methodology

3.1 Available Dataset

This study utilizes an integrated dataset acquired from the NEAG-5 Field, Abu Gharadig Basin, Western Desert, Egypt (BAPETCO 2012). The dataset includes conventional wireline logs, routine core analysis (RCAL), special core analysis (SCAL), X-ray diffraction (XRD) and production data from multiple wells (Table 1) (Corex 2019).

Table 1. Summary of datasets used in this study and their primary applications within the integrated reservoir characterization workflow.

Dataset	Source / Wells	Primary Application
Conventional wireline logs (GR, RHOB, NPHI, Rt)	All NEAG-5 wells	Petrophysical evaluation, electrofacies modeling
Routine core analysis (RCA)	NEAG 5-9	Rock typing, hydraulic flow unit characterization
Special core analysis capillary pressure (SCAL)	NEAG 5-9	Saturation height function development
X-ray diffraction (XRD)	NEAG 5-9 (12 plugs)	Quantitative clay mineral characterization
Production & completion data	Multiple NEAG-5 wells	Dynamic model validation

3.2 Integrated Workflow

An integrated reservoir characterization workflow was developed to reduce uncertainty in water saturation estimation and establish a direct relationship between reservoir quality, clay mineralogy, and production performance (Fig. 3). The workflow begins with core based reservoir rock typing using hydraulic flow unit analysis, in which Reservoir Quality Index (RQI), Normalized Porosity Index (NPI), and Flow Zone Indicator (FZI) are calculated from routine core measurements to define distinct reservoir rock types (Amaefule et al. 1993). The resulting rock type classification was subsequently propagated throughout uncored wells using an Indexed Probabilistic Self Organizing Map (IPSOM) electrofacies model trained with conventional wireline logs.

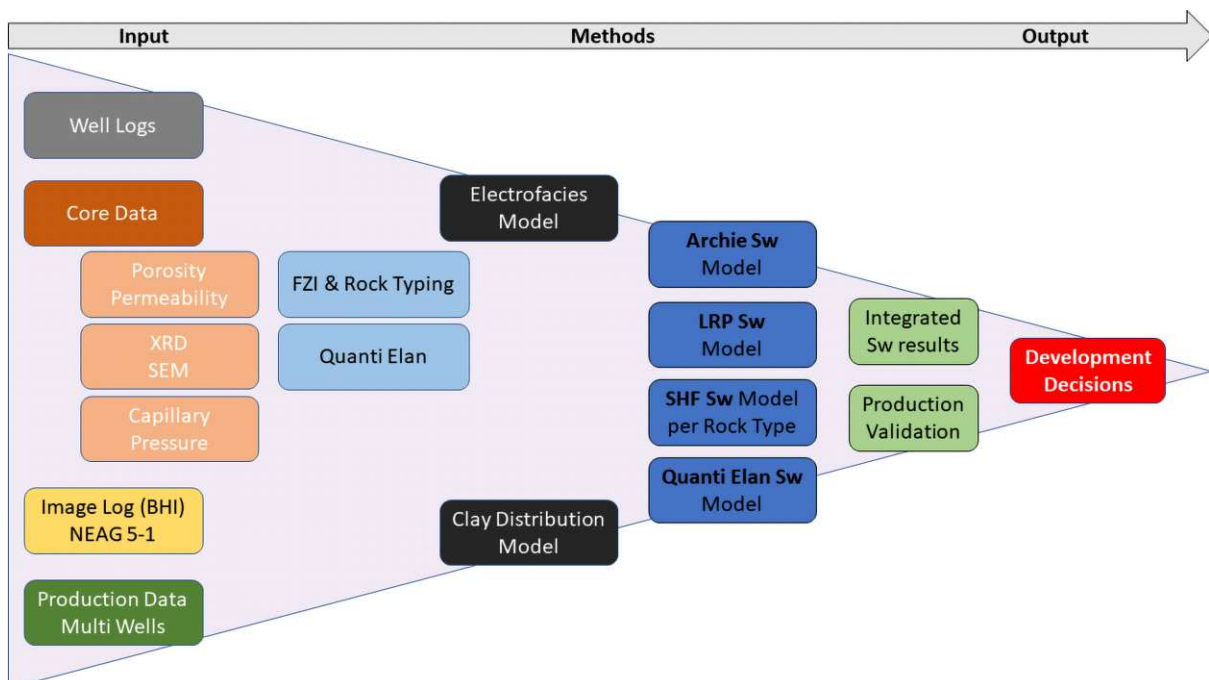


Fig. 3. Integrated workflow describing the input data used and the output products at each stage of the reservoir characterization process.

3.3 Rock Typing Methodology

Reservoir rock typing was performed using the Hydraulic Flow Unit (HFU) concept proposed by (Kassab and Teama 2018; El-Sayed et al. 2021). This approach integrates porosity and permeability measurements to characterize pore throat architecture and reservoir flow behavior. The Reservoir Quality Index (RQI), Normalized Porosity Index (NPI), and Flow Zone Indicator (FZI) were calculated from routine core analysis data as follows:

$$RQI = 0.0314 \sqrt{\frac{K}{\phi}} \quad (1)$$

$$\phi_z = \left(\frac{\phi}{1-\phi} \right) \quad (2)$$

$$FZI = \frac{RQI}{\phi_z} \quad (3)$$

3.4 Electrofacies Modeling

To extend the rock type classification beyond cored intervals, an electrofacies model was developed using the Indexed Probabilistic Self Organizing Map (IPSOM) technique. IPSOM is an unsupervised neural network algorithm capable of identifying multidimensional relationships between petrophysical measurements and reservoir properties. The model was trained using conventional wireline logs (GR, RHOB, NPHI, and Rt) and the core derived rock type classification from NEAG 5-9 (Kassab et al. 2021, 2025). The trained model was subsequently applied to uncored wells to generate continuous electrofacies predictions throughout the reservoir interval.

3.5 Mineralogical Modeling

Quantitative mineralogical evaluation was conducted using the Quanti Elan inversion workflow (Nabih and El Shinawi 2020). The inversion solves the response equation:

$$t_i = \sum_{i=1}^{nfc} R_i * V_i \quad (4)$$

where t is the logging tool measurement, V is the volumetric fraction of each formation component, and R is the response matrix containing the parameter values that each tool reads given 100% of each component. Mineral selection and response parameters were constrained using XRD from NEAG 5-9 core samples.

3.6 Water Saturation Modeling

Four independent water saturation approaches were evaluated to investigate the influence of clay minerals and reservoir heterogeneity on saturation estimation. (1) The conventional Archie equation (Archie 1942), calibrated using core derived cementation and saturation exponents with formation water resistivity, served as the baseline.

(2) The Low Resistivity Pay (LRP) methodology corrected resistivity for the effects of laminated and dispersed shale below logging tool resolution, using neutron density and gamma ray crossplot endpoints (E.C. Thomas; S.J. Stieber 1975). (3) Quanti Elan mineral based evaluation incorporated mineralogical volumes to quantify the impact of clay distribution on calculated water saturation. (4) Saturation Height Function (SHF) modeling employed Leverett J-function transformations (Leverett 1941) calibrated to individual reservoir rock types, generating rock type dependent water saturation equations that reflect differences in pore throat architecture and reservoir quality.

3.7 Dynamic Validation

The reliability of the proposed workflow was evaluated through integration with independent geological and production datasets. The four water saturation models were assessed using actual field performance data from producing and poorly performing wells, with production behavior, cumulative oil production, and reservoir response compared against predicted rock type distributions, clay mineral content, and calculated water saturation profiles.

4. Results

4.1 Reservoir Rock Types and Electrofacies Distribution

Hydraulic Flow Unit analysis revealed four distinct reservoir rock types within the Middle Bahariya reservoir. The identified rock types exhibit significant variations in porosity, permeability, and flow capacity, reflecting the strong heterogeneity of the reservoir. The distribution of FZI values demonstrated three dominant populations and one minor population, supporting the classification of four rock types representing different pore throat architectures and reservoir qualities (Fig. 4).

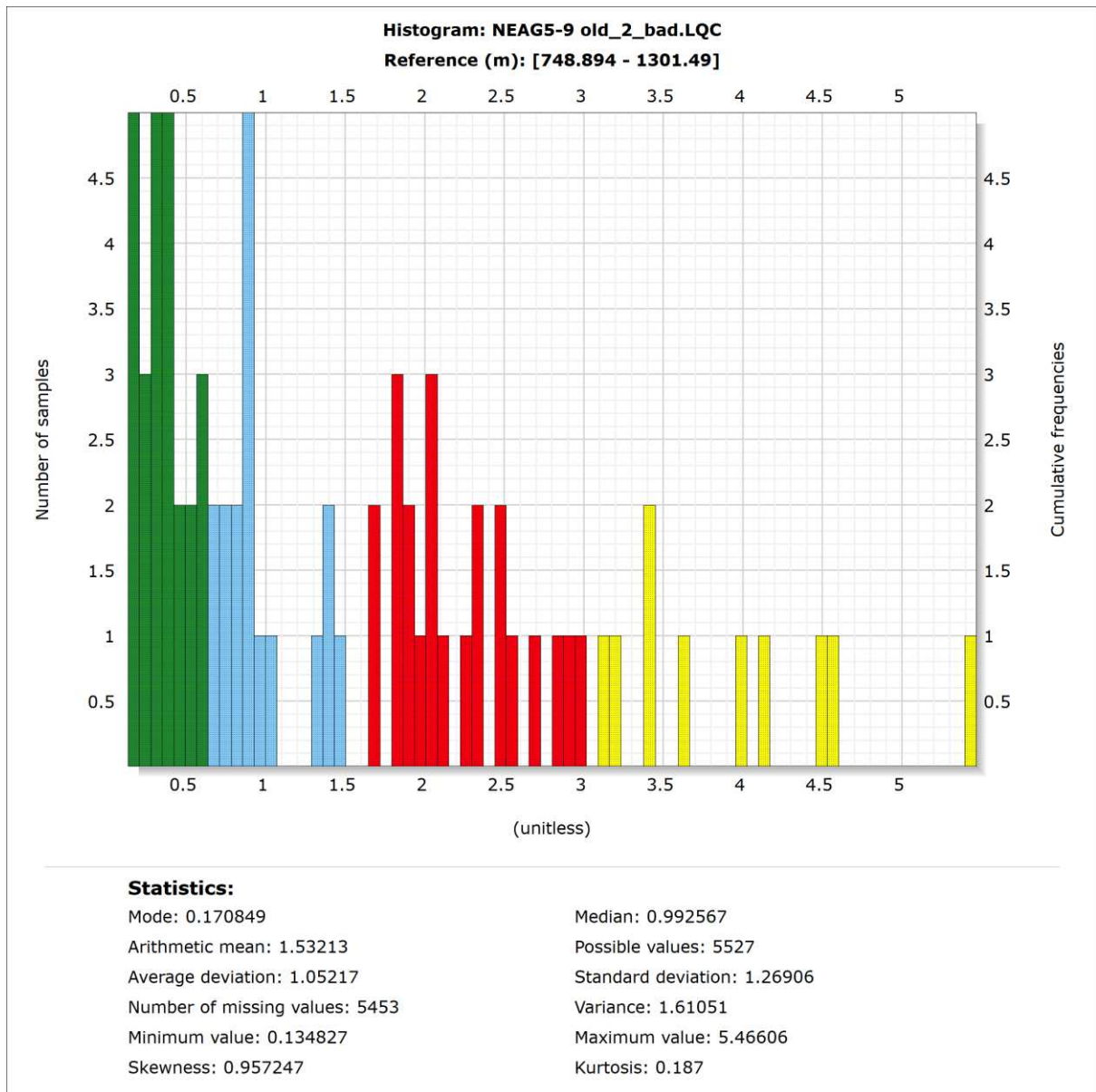


Fig. 4. Histogram showing FZI value clustering, illustrating four distinct reservoir rock type populations within the Middle Bahariya reservoir(Corex 2019).

The IPSOM electrofacies model successfully propagated the rock type classification from cored intervals to uncored wells using conventional wireline logs, capturing the vertical and lateral variability of reservoir quality throughout the field (Fig. 5).

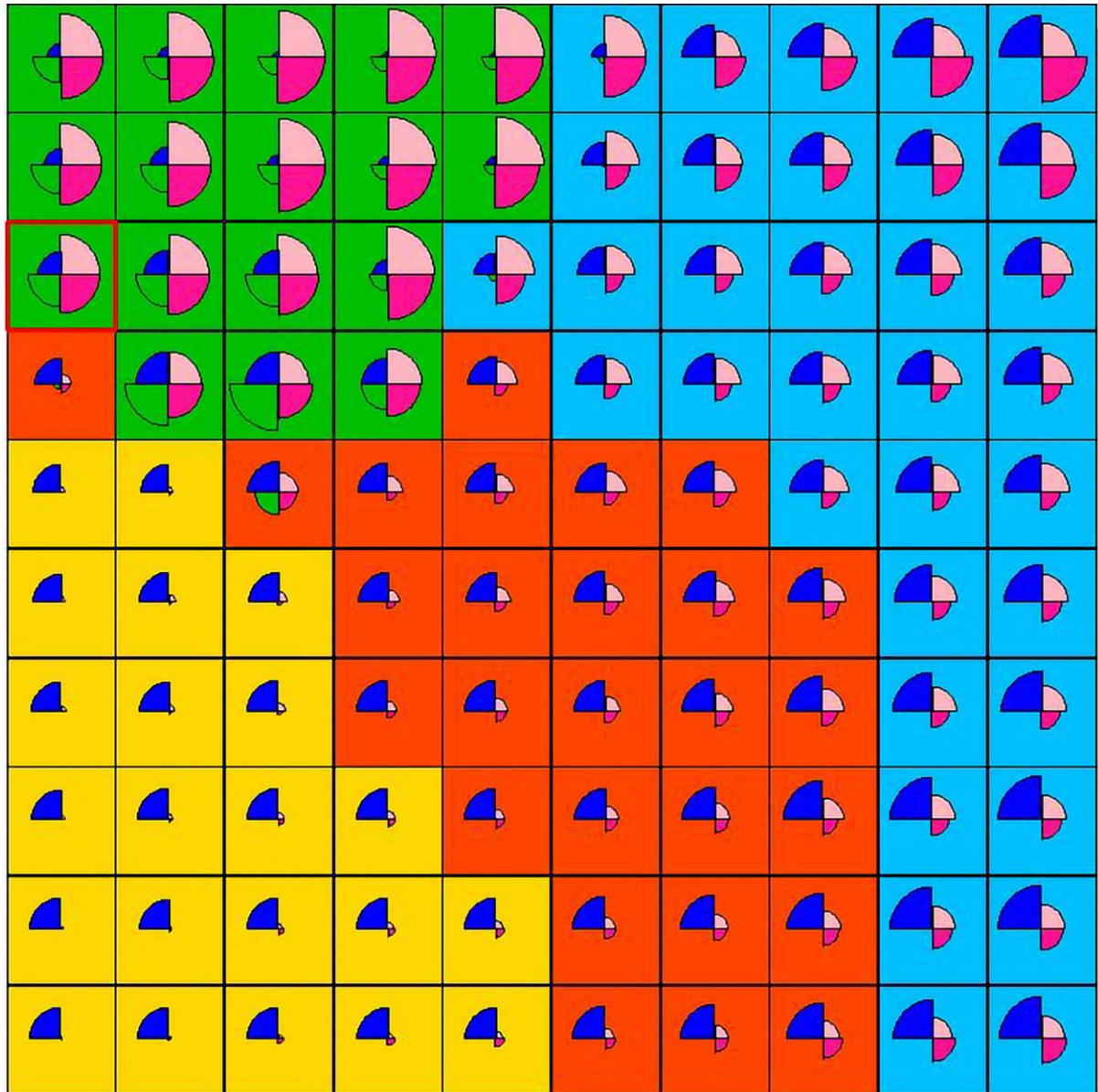


Fig. 5. Self Organized Map (SOM) for FZI classified into four reservoir rock types (RTs), illustrating the electrofacies model training output and rock type distribution.

The distribution and occurrence patterns of clay minerals identified in NEAG-5 show a clear correspondence with facies type and reservoir quality, setting the stage for the mineralogical characterization discussed in the following section.

4.2 Mineralogical Characterization and Clay Distribution

XRD analysis was performed on 12 core plugs from NEAG 5-9 (Fig. 6), identifying kaolinite, illite, mixed layer illite smectite, and glauconite as the dominant clay minerals. The distribution of these clay minerals was found to be closely associated with reservoir quality variations. High quality reservoir intervals were generally

characterized by lower clay content and a predominance of kaolinite, whereas poor quality intervals showed increased concentrations of illite, mixed layer clays, and glauconitic components.

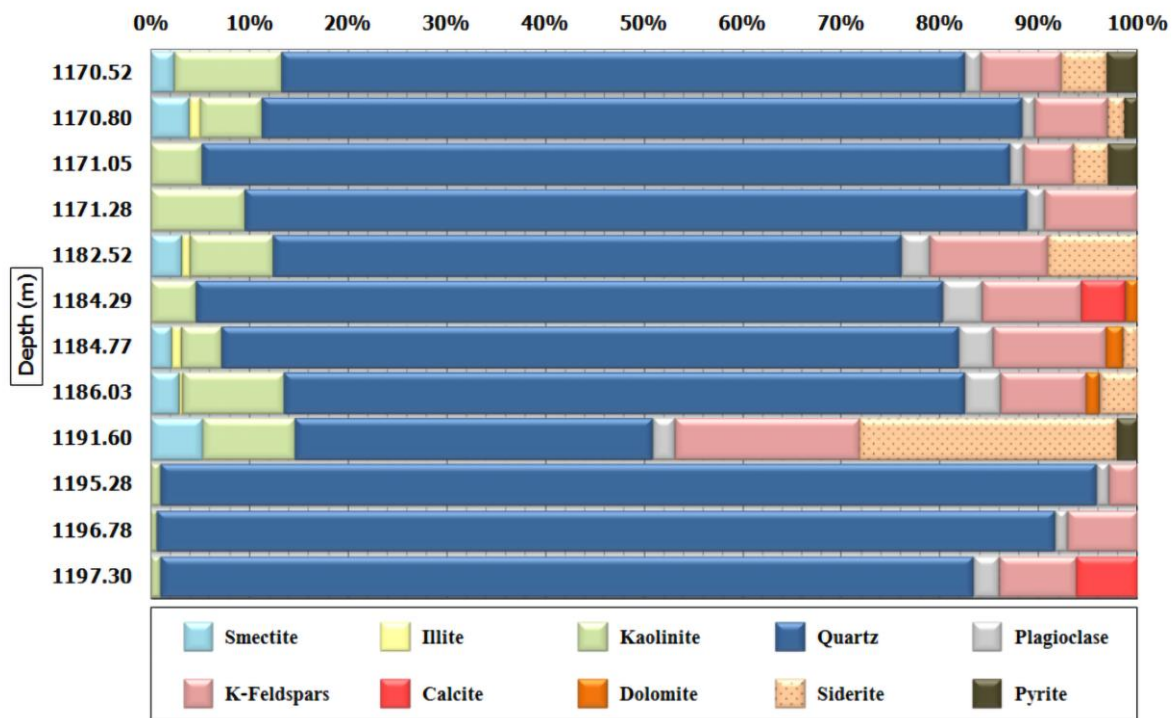


Fig. 6. XRD results for whole rock (WR) analysis (wt%) from 12 core plugs in NEAG 5-9, showing the mineralogical composition of the Middle Bahariya reservoir (Corex 2019).

The Quanti Elan model, calibrated against XRD measurements, showed an excellent match between predicted and measured mineral volumes, particularly for quartz and total clay content (Fig. 7).

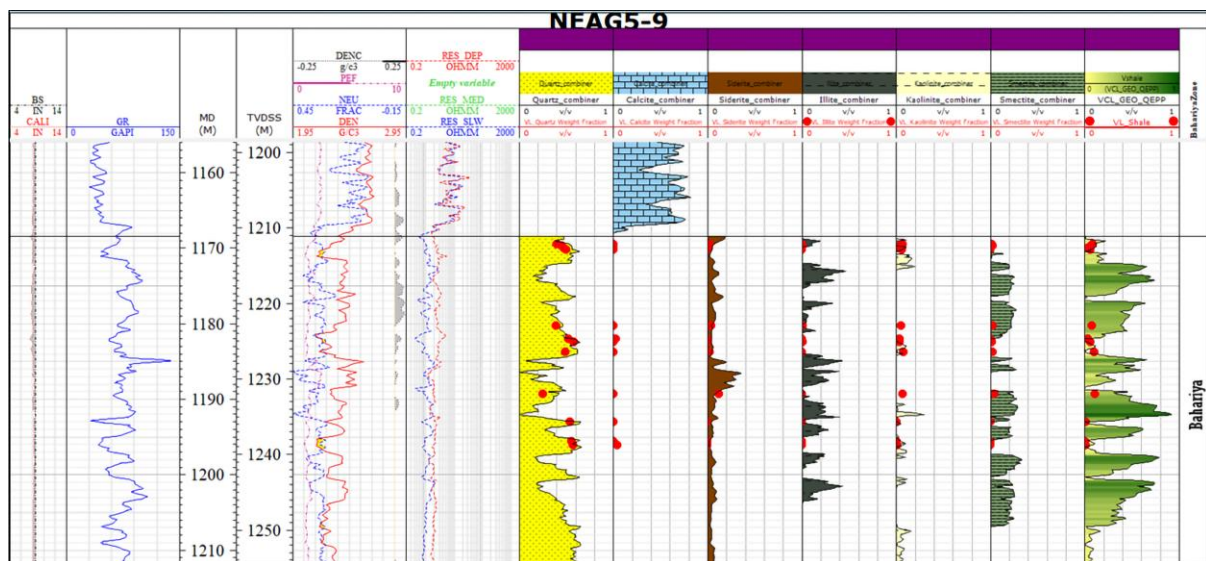


Fig. 7. Log plot showing the mineral content derived from Quanti Elan inversion matched with XRD data in NEAG 5-9, demonstrating the excellent calibration of the mineralogical model.

4.3 Water Saturation Evaluation

4.3.1 Archie Water Saturation

Archie water saturation was calculated using core derived parameters ($m = 1.68$, $n = 2.01$) and formation water resistivity ($R_w = 0.13 \Omega \cdot m$), established through the SCAL workflow presented (Fig. 8). While acceptable results were obtained in relatively clean sandstone intervals, the model consistently predicted excessively high water saturations within clay rich zones. The overestimation was particularly evident within low resistivity intervals where conductive clay minerals significantly influenced formation resistivity (Archie 1942; Waxman and Smits 1968), indicating that conventional Archie evaluation alone is insufficient for reliable saturation assessment within the Middle Bahariya shaly sand reservoir (El-Dabaa et al. 2022).

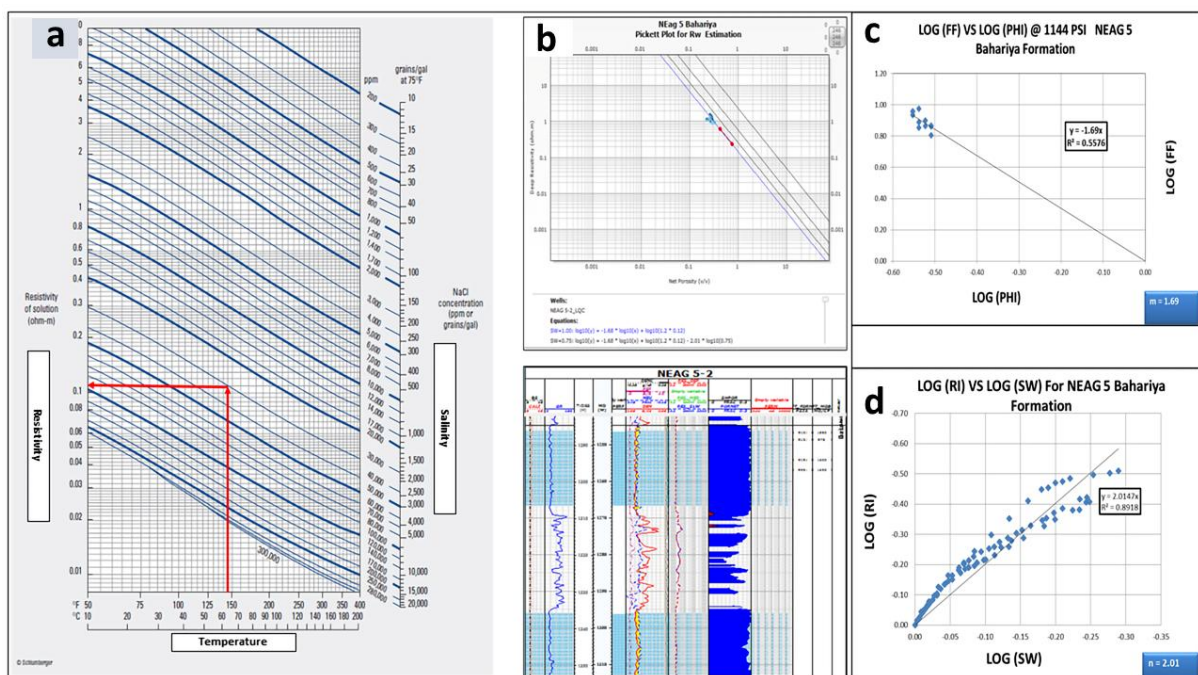


Fig. 8. NEAG 5-9 SCAL data: a) Formation salinity and reservoir temperature for formation water resistivity (R_w) determination, b) Pickett plot for interactive R_w estimation in clean water bearing zones, c) Formation resistivity factor vs. core porosity crossplot for cementation factor (m) (Kassab et al. 2025), d) Resistivity index vs. core water saturation crossplot for saturation exponent (n).

4.3.2 Low Resistivity Pay (LRP) Evaluation

The LRP model was applied to correct resistivity measurements affected by thin shale laminations below tool resolution. The first step involved selecting clean sandstone, shaly sand, and shale intervals on log plots to develop endpoints for both neutron-density and gamma-ray crossplots. Clean sand selections were guided by the electrofacies model, while shale intervals were identified using a GR histogram. The bulk density versus neutron porosity crossplot was then used to delineate the lamination trend between the clean sand and shale endpoints

(Fig. 9). Application of the LRP methodology reduced calculated water saturation in shaly sands from approximately 75% to 50–55%. Compared with Archie results, the LRP model improved the identification of hydrocarbon bearing intervals, particularly within moderate and low quality rock types where clay conductivity exerted a strong influence on resistivity measurements (Kassab et al. 2015; Osman et al. 2021).

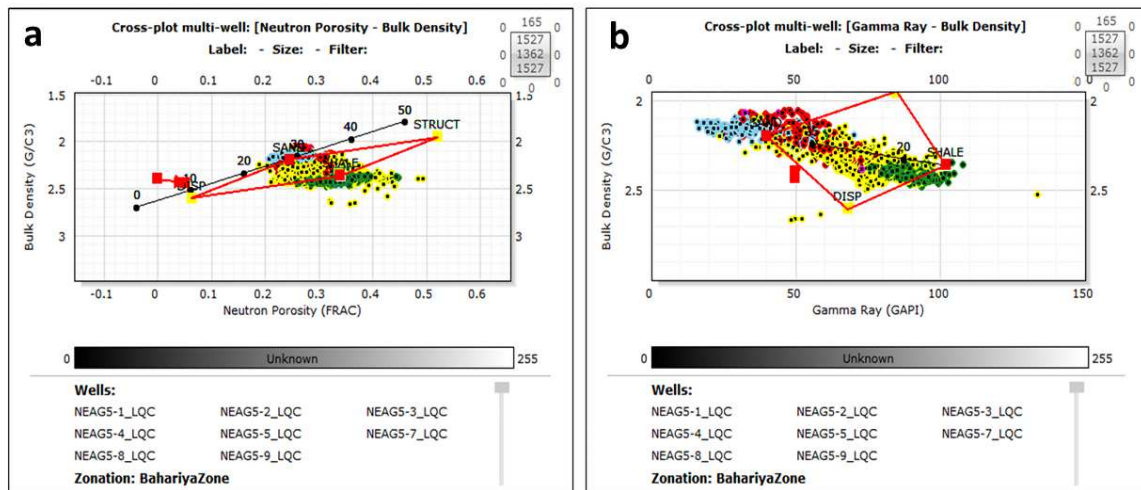


Fig. 9. a) Neutron-density crossplot, b) Gamma ray-density crossplot for clean sand, shaly sand, and clean shale used for developing the end points for the Low Resistivity Pay model (E.C. Thomas; S.J. Stieber 1975).

4.3.3 Saturation Height Function (SHF) Modeling

Capillary pressure measurements obtained from SCAL analysis revealed a strong dependence of irreducible water saturation on reservoir quality. To account for the heterogeneity of the Middle Bahariya reservoir, the capillary pressure data were grouped into four reservoir rock types based on permeability and porosity characteristics.

The highest quality reservoir intervals (RT-4) are characterized by permeability greater than 1000 mD, relatively high porosity, and low irreducible water saturation values, indicating large interconnected pore throats and excellent hydrocarbon storage potential. In contrast, the lowest quality rock type (RT-1) exhibits permeability below 10 mD and high irreducible water saturation, reflecting poor pore connectivity and a greater proportion of bound water (Fig. 10).

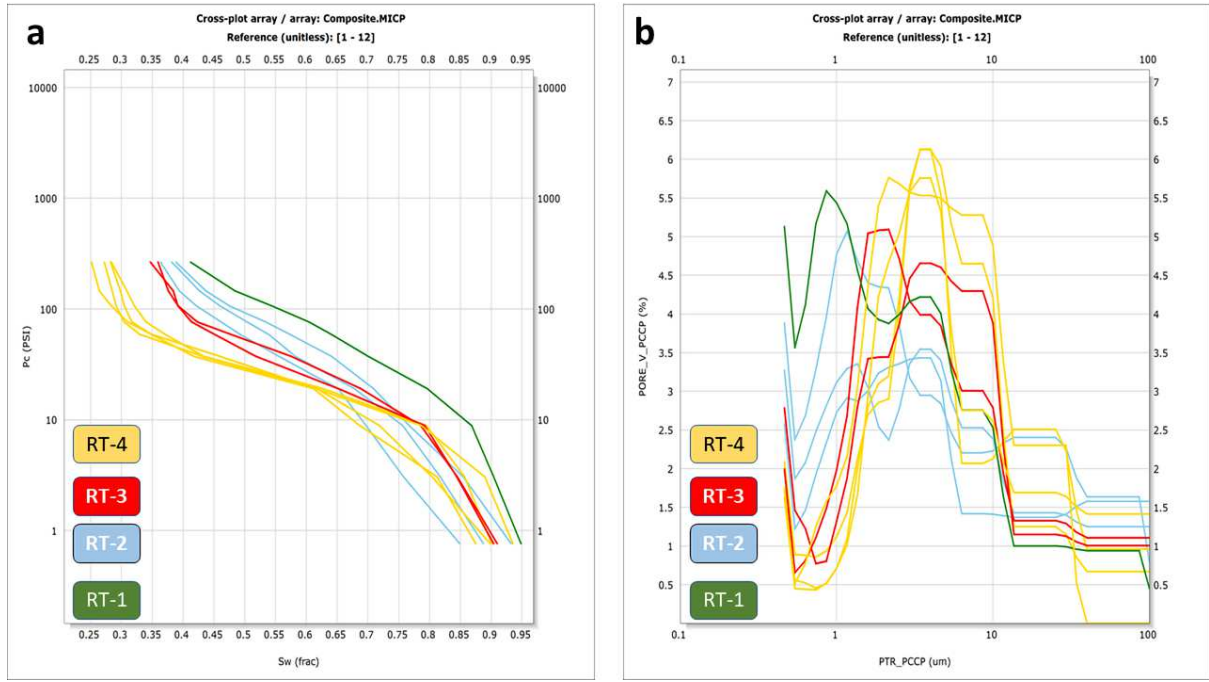


Fig. 10. a) Capillary pressure data, b) Pore throat size distribution colour coded by the four reservoir rock types defined by FZI method.

Intermediate rock types (RT-2 and RT-3) display progressive changes in permeability, porosity, and irreducible water saturation, demonstrating a systematic relationship between reservoir quality and fluid distribution. The relationship between porosity and irreducible water saturation was established for 10 core plugs, providing input parameters for J-function fitting. Saturation height modeling was then performed using the Leverett J-function fitting method (Leverett 1941) based on available oil-brine centrifuge capillary pressure data, using the following equations:

$$S_{wr} = S_w - S_{wi} = aJ^b \quad (5)$$

$$J = \frac{P_c}{\sigma \cos \theta} \sqrt{\frac{K}{\phi}} \quad (6)$$

$$P_c = \frac{2\sigma \cos \theta}{r} = (\rho_w - \rho_o)gh \quad (7)$$

J-function fitting was performed across all permeability ranges (Fig. 11), revealing distinct fitting lines for each permeability class. Formation pressure data from NEAG 5-1 and NEAG 5-2 were used to establish oil and water gradients and free water levels for two separate field segments (Fig. 12) (Dakhelpour-Ghoveifel et al. 2019). The saturation height model parameters per rock type are summarized in (Table 2) and the J-Function parameters.

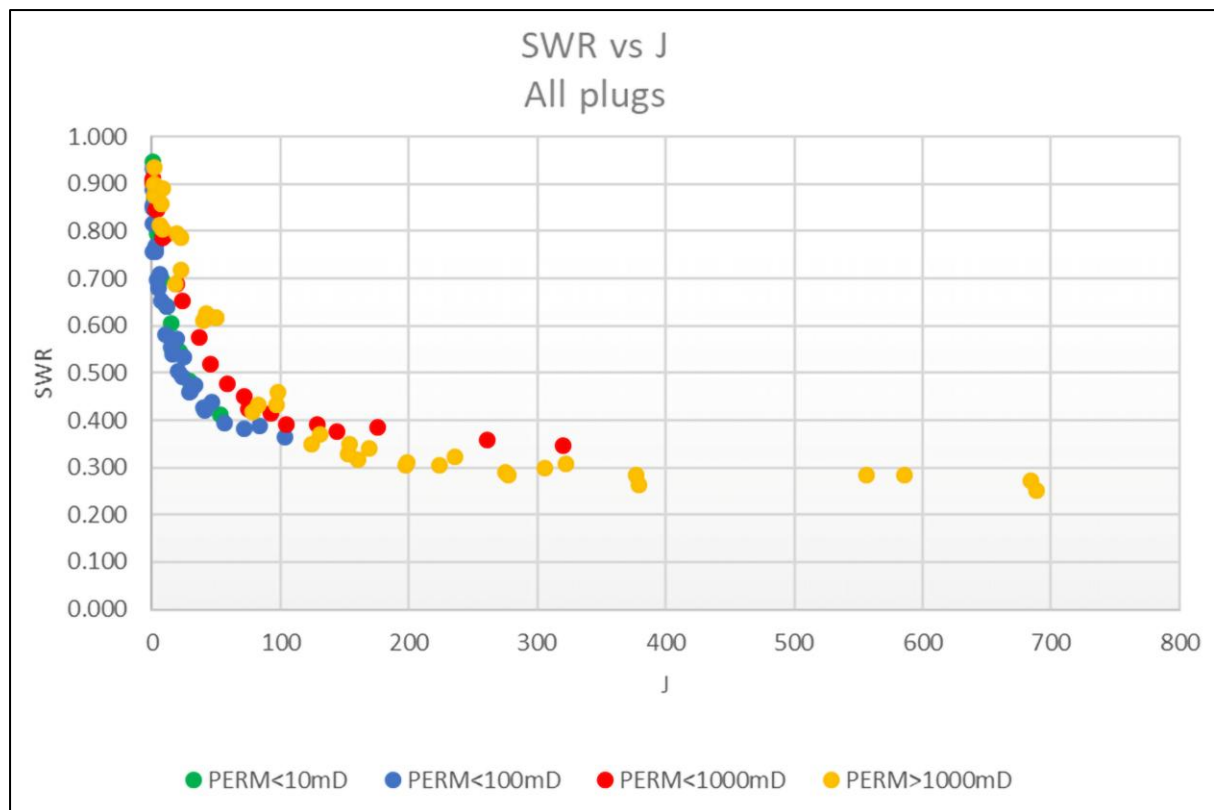


Fig. 11. J-function fitting parameters plot, showing distinct fitting lines for the four permeability classes corresponding to the four reservoir rock types.

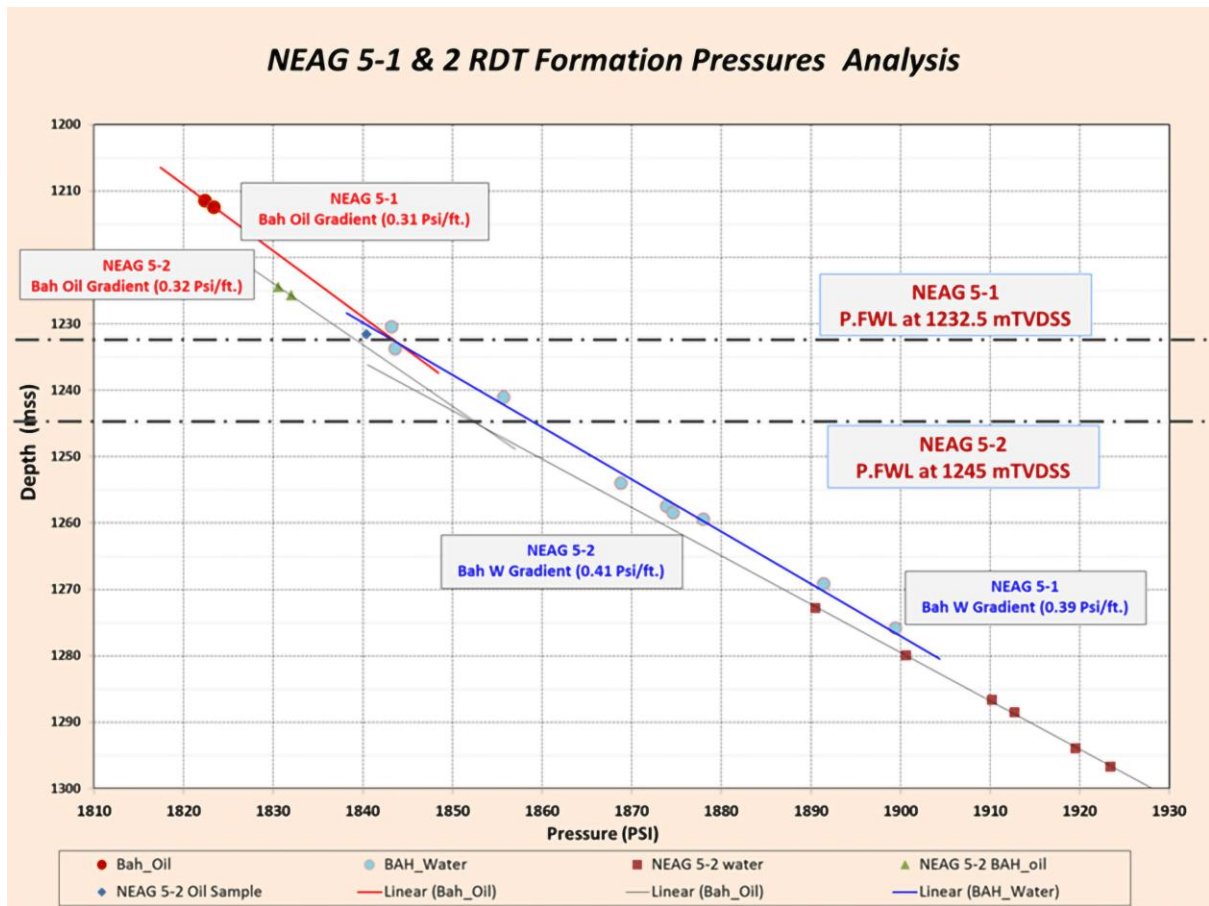


Fig. 12. Formation pressure analysis for NEAG 5-1 and NEAG 5-2 wells, showing oil gradient, water gradient, and free water levels for the two field segments.

Table 2. Saturation Height Model parameters.

Parameters	Well Logs (Archie)	Remarks
Swi	0.41 (K<10md)	Cap-Curve
	0.364 (K<100md)	
	0.347(K<1000md)	
	0.251 (K>1000md)	
FWL	1232.5 mTVDSS OW-FWL NEAG 5-1 block	Formation Pressure
	1245 mTVDSS GW-FWL NEAG 5-2 block	Analysis
$\sigma \cos\theta_{res}$	26 (Oil-Brine System)	Standard
$\sigma \cos\theta_{lab}$	42 (Oil-Brine System)	Standard
ρ_w	0.41 psi/ft	

ρ_w	0.31 psi/ft	Formation Pressure Analysis
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Four water saturation equations were developed per rock type using J-function transforms:

$$S_w = S_{wi} + aJ^b \quad (8)$$

$$RT_1 \quad S_{w_SHF} = 0.41 + 0.84 * \left[\frac{(FWL-TVDss)*(0.41-0.31)*3.281}{26} * \sqrt{\frac{K}{\phi}} \right]^{-0.84} \quad (9)$$

$$RT_2 \quad S_{w_SHF} = 0.36 + 0.42 * \left[\frac{(FWL-TVDss)*(0.41-0.31)*3.281}{26} * \sqrt{\frac{K}{\phi}} \right]^{-0.47} \quad (10)$$

$$RT_1 \quad S_{w_SHF} = 0.34 + 0.97 * \left[\frac{(FWL-TVDss)*(0.41-0.31)*3.281}{26} * \sqrt{\frac{K}{\phi}} \right]^{-0.5} \quad (11)$$

$$RT_1 \quad S_{w_SHF} = 0.25 + 2.82 * \left[\frac{(FWL-TVDss)*(0.41-0.31)*3.281}{26} * \sqrt{\frac{K}{\phi}} \right]^{-0.82} \quad (12)$$

The water saturation and J-function relations for each rock type are displayed in (Fig. 13). The SHF model per rock type provides a good match with Archie (S_{w_AR}) and Low Resistivity Pay (S_{w_LRP}) models at transition zones in clean sand intervals, and gives a better match at both low and high permeability intervals than the other approaches. The saturation height model is recommended for use across all permeability ranges of the Middle Bahariya Formation.

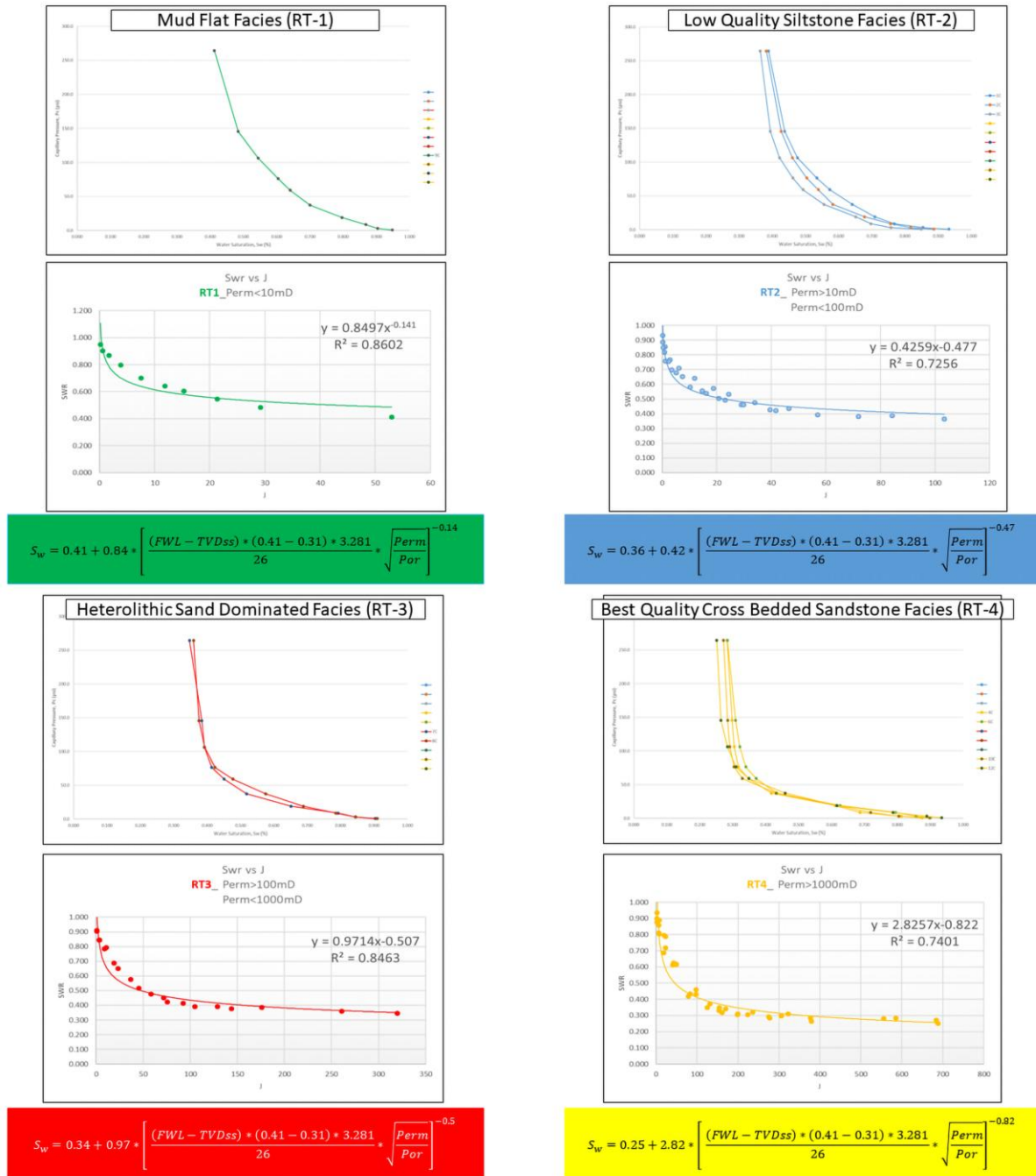


Fig. 13. Water saturation and J-Function relations for each reservoir rock type (RT), illustrating the four distinct capillary pressure–saturation transforms used in the SHF model.

4.4 Comparison of Water Saturation Models

The comparison of Archie, LRP, Quanti Elan, and SHF saturation models highlights the significant influence of clay minerals and reservoir heterogeneity on water saturation estimation (Fig. 14). In clean sandstone intervals, all models produced comparable saturation values, indicating minimal impact from clay conductivity. In contrast, substantial differences were observed within shaly intervals: Archie consistently generated the highest water

saturation estimates, while LRP and Quanti Elan reduced the calculated water saturation by accounting for clay effects. The rock type dependent SHF model produced the most geologically consistent results. In the low quality shaly sand (RT-2), the application of LRP and SHF models resulted in an approximately 50% decrease in calculated water saturation relative to Archie (Fig. 15). The integrated evaluation demonstrates that saturation estimation is strongly controlled by reservoir quality and clay mineral distribution, and that the use of a single field wide saturation model is inadequate for accurately characterizing fluid distribution in this heterogeneous reservoir system(Kassab et al. 2025).

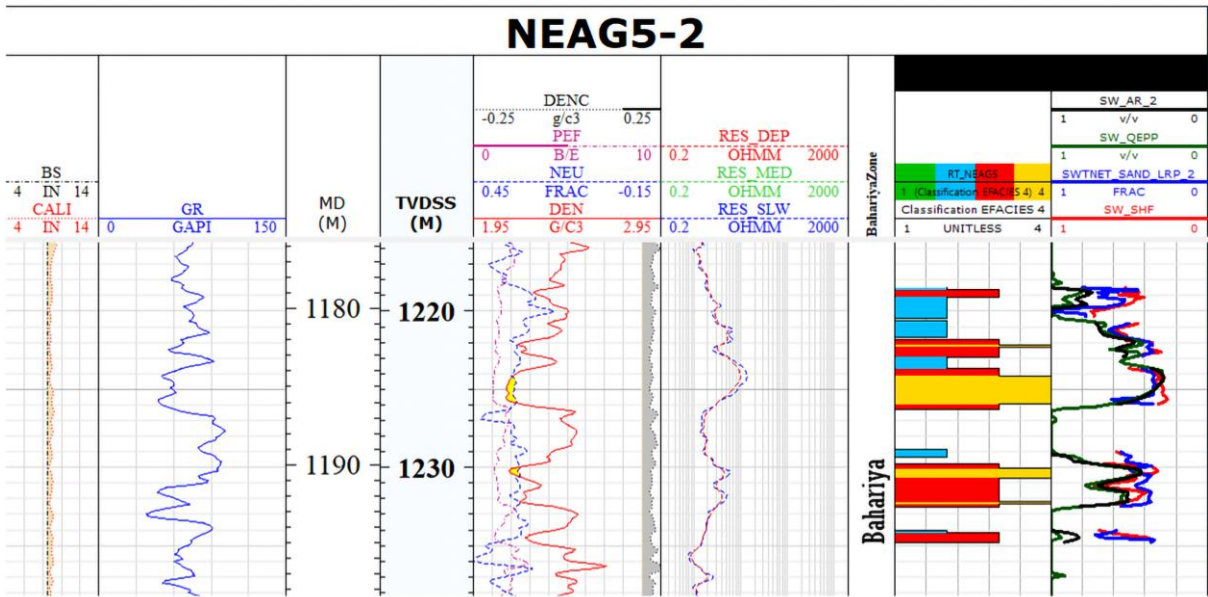


Fig. 14. Log plot showing the difference in saturation calculations between the Archie, Low Resistivity Pay, and Saturation Height Modeling (SHF) models per rock type.

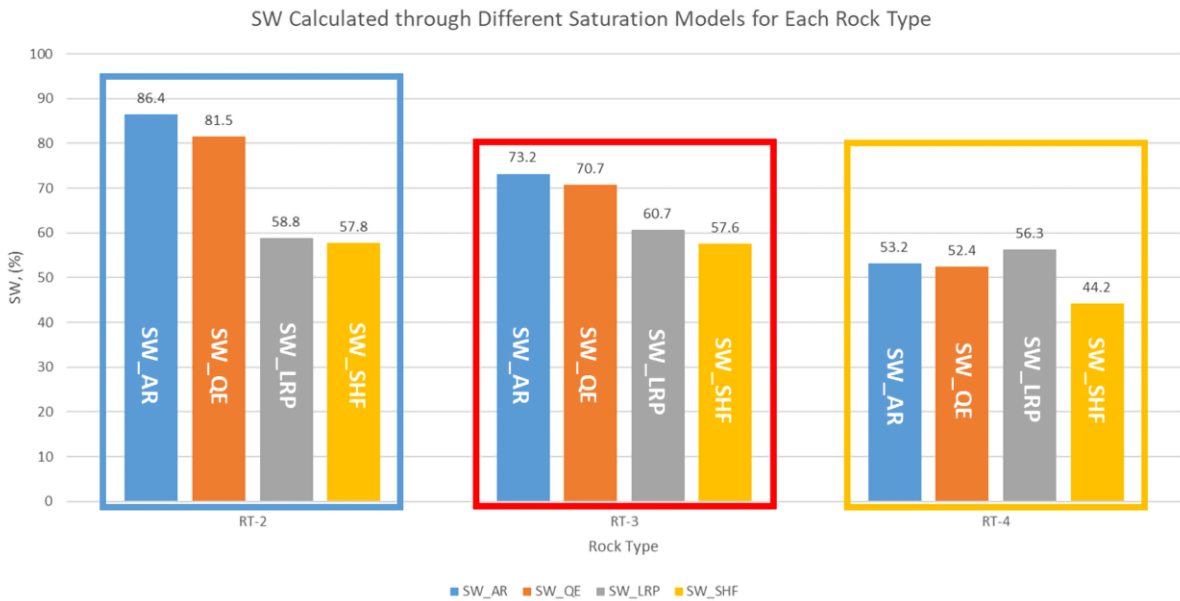


Fig. 15. Difference in saturation calculations between the Archie, Quanti Elan, Low Resistivity Pay, and Saturation Height Modeling (SHF) models per rock type (El-Bendary et al. 2017).

5. Field Development Implications

The revised reservoir characterization model has important implications for field development and reservoir management. The integrated workflow improved net pay identification and revealed productive intervals previously underestimated by conventional evaluation techniques. As a result, hydrocarbon volumes were significantly revised, with STOIP estimates increasing from approximately 5 MMstb to 19 MMstb. Injection was isolated from high quality intervals to mitigate water cut, and a perforation campaign targeting newly identified pay added more than 90 m of net oil sand across the field.

NEAG 5-1, the best producer (0.703 MMstb), is dominated by high quality electrofacies and low clay content (Fig. 16).

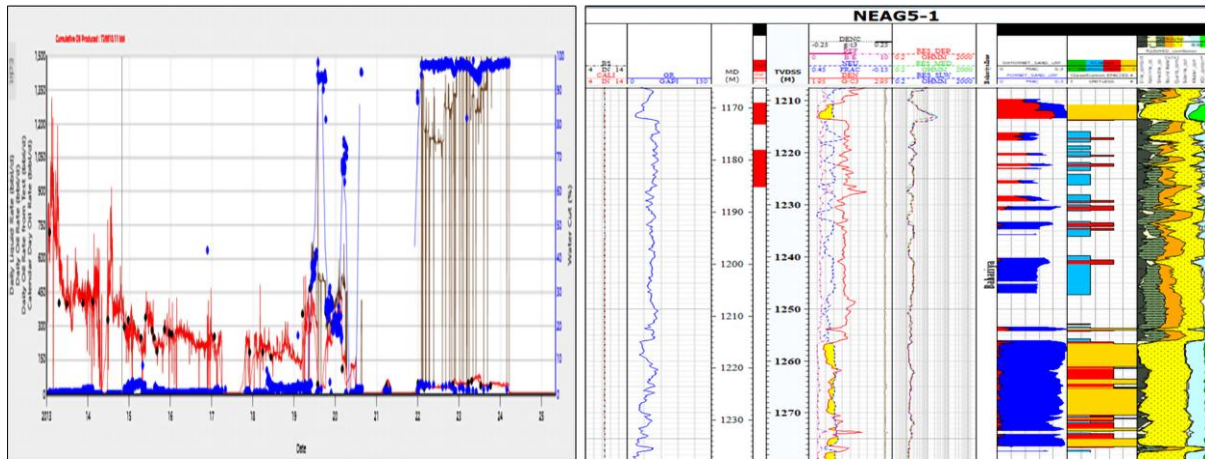


Fig. 16. Log plot for NEAG 5-1 showing the integration between electrofacies by the IPSOM module and the Quanti Elan mineralogical model versus production history.

In contrast, NEAG 5-3, despite multiple fracturing attempts, produced only 0.057 MMstb owing to the dominance of clay-rich low quality facies (Fig. 17), consistent with the poor production performance and the limited effectiveness of stimulation in clay dominated facies.

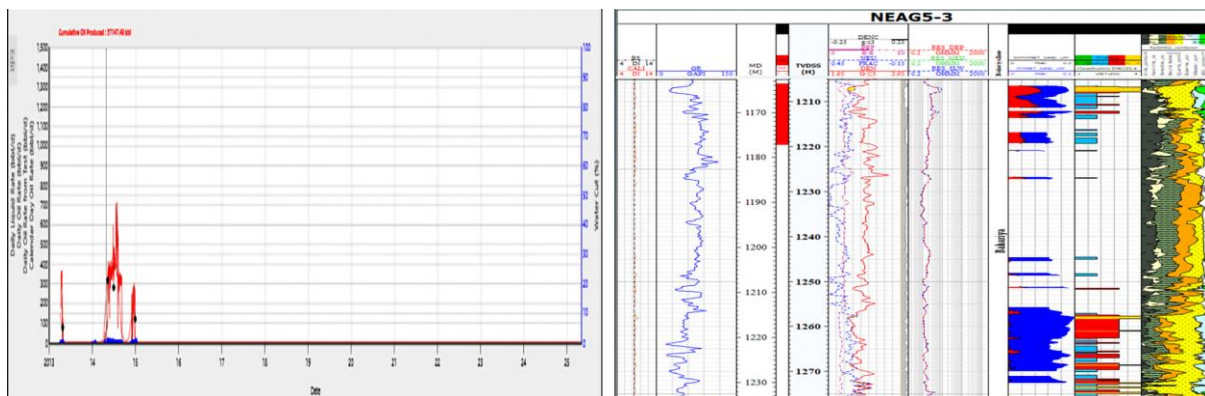


Fig. 17. Log plot for NEAG 5-3 showing the integration between electrofacies by the IPSOM module and the Quanti Elan mineralogical model versus production history, illustrating the impact of clay dominated facies on well performance.

The study demonstrates that reservoir quality and clay mineral distribution must be considered during perforation design, completion planning, and waterflood management. High quality rock types represent the primary production targets, whereas clay rich intervals require careful evaluation. Horizontal wells were recommended for illite dominated zones, representing the only economically viable development option in low quality facies. The proposed workflow provides a practical framework for optimizing future development activities in the NEAG-5 Field and other heterogeneous low resistivity shaly sand reservoirs.

6. Discussion

The results demonstrate that water saturation uncertainty within the Middle Bahariya reservoir is primarily controlled by the interaction between reservoir quality, facies distribution, and clay mineral occurrence. Although Archie evaluation remains effective in relatively clean sandstones, its application in clay rich intervals leads to systematic overestimation of water saturation due to the conductive contribution of clay minerals (Archie 1942; Waxman and Smits 1968; Kolodzie 1980). The discrepancy between Archie saturation estimates and actual production behavior confirms that resistivity alone cannot adequately characterize hydrocarbon saturation in low resistivity shaly sands.

The dynamic production response of the field further supports these conclusions. NEAG 5-1, one of the most productive wells in the field, is dominated by high quality reservoir facies characterized by lower clay content and favorable rock types. In contrast, NEAG 5-3 exhibited poor production performance despite hydraulic fracturing treatments, and is characterized by lower quality facies with elevated clay concentrations. This stark contrast underscores the critical role of facies architecture and clay mineralogy in controlling producibility, independent of structural position or stimulation history.

7. Conclusions

The following conclusions are drawn from this integrated study of the Middle Bahariya Formation in the NEAG-5 Field:

1. The Middle Bahariya reservoir in the NEAG-5 Field is a highly heterogeneous shaly sandstone system characterized by significant variations in facies distribution, reservoir quality, and clay mineralogy, with clay content and distribution serving as the primary controls on reservoir performance and water saturation estimation.

2. Conventional Archie evaluation systematically overestimates water saturation in clay rich low resistivity intervals due to the conductive contribution of clay minerals, leading to underestimation of net pay and hydrocarbon volumes.

3. Hydraulic Flow Unit analysis and IPSOM electrofacies modeling successfully identified four reservoir rock types representing distinct flow capacities and pore throat architectures across the field, enabling consistent reservoir quality characterization in both cored and uncored wells.

4. Integrated XRD and Quanti Elan analyses demonstrated that both clay volume and clay mineral type exert a strong control on reservoir quality and electrical behavior. Kaolinite dominated facies preserve porosity and permeability, whereas illite rich and glauconitic facies exhibit significant permeability degradation.

5. The integrated workflow successfully linked reservoir quality, clay mineral distribution, water saturation behavior, and dynamic production response, resulting in a significant reduction in evaluation uncertainty.

6. Application of the integrated workflow increased STOIIP from approximately 5 MMstb to 19 MMstb, enabled optimized perforation targeting, improved waterflood management, and identified horizontal wells as the preferred development strategy for illite dominated low quality facies.

7. The proposed methodology provides a robust and repeatable framework for reserve estimation, development planning, and production optimization in heterogeneous low resistivity shaly sand reservoirs.

Ethics information

This manuscript has not been submitted to more than one journal for simultaneous consideration. The submitted work is original and not has been published elsewhere in any form or language (partially or in full). The results presented clearly, honestly, and without fabrication, falsification or inappropriate data manipulation (including image based manipulation).

Author contribution

The Author contribution is equal contribution.

Conflicts of interest

On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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Data Availability

The data used in this study are available from the corresponding author upon reasonable request.

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329 Abbreviation List

Full Name	Abbreviation
North East Abu Gharadig	NEAG
X-ray diffraction	XRD
scanning electron microscopy	SEM
special core analysis	SCAL
Routine core analysis	RCA
Rock Type	RT
Indexed and Probabilized Self Organizing Map	IPSOM
Permeability	K, Perm
Porosity	$\emptyset$
Pore throat	R
Low Resistivity Pay	LRP
Saturation Height Modeling	SHM
Stock Tank Oil Initially in Place	STOIIP
True Vertical Depth Sub Sea	TVDSS
Stock tank barrel per day	stb/d
meter	m
Borehole Image	BHI
Gamma Ray	GR
Bulk Density	RHOB
Neutron Porosity	NPHI
True Resistivity	Rt
Flow Zone Indicator	FZI
Normalized Porosity Index	NPI, $\emptyset_z$
Reservoir Quality Index	RQI
Logging tool measurement	t
Volumetric fraction	V
Response matrix	R
whole rock	WR
Cementation Factor	m
Saturation Factor	n
Formation Water Resistivity	Rw
Water Saturation	Sw

Irreducible water saturation	Swi
Reducible water saturation	Swr
J-Leverret Function	J
Constants	a&b
Pc = The capillary pressure	Pc
The interfacial tension (fluid property)	σ
The contact angle (related to wettability and rock fluid interaction)	θ
The pore radius (rock property related to permeability and porosity)	r
The density for water and hydrocarbon (gas or oil)	ρ
The gravity	g
The height above FWL (transition zone)	h
Million Stock tank barrel	MMstb

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