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Reservoir Recharacterization and Hydrocarbon Volume Re-estimate of Miocene D10/Ph-02 Sand, Phyl Field, Offshore Niger Delta

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ABSTRACT

This study presents an integrated reservoir recharacterization of the D-10/Ph-02 intervals in the Phyl Field, offshore Niger Delta Basin, aimed at refining hydrocarbon volume estimates and optimizing field redevelopment. Production in the field ceased in 2020 due to limitations in the existing reservoir model, including poor seismic-well integration and uncertain fluid contacts. A multidisciplinary approach was adopted, combining reprocessed 3D seismic data, well log analysis, biostratigraphy, and production history to revive production in the field. Seismic interpretation revealed complex fault architecture listric growth faults, synthetic and antithetic faults, and Miocene mud-filled canyons resulting in reservoir compartmentalization and stratigraphic trapping. Petrophysical evaluation showed high reservoir quality, with average porosity of 30%, net-to-gross ratio up to 98%, and water saturation averaging 23%. A revised oil-water contact at -4950 ft TVDSS led to a reduction in 2P STOOIP from 18.13 to 13.10 MMSTBO, while recovery factor improved from 28.8% to 45.4%. Stratigraphic and biostratigraphic analysis confirmed a coastal deltaic depositional environment, aiding reservoir correlation and facies prediction. Production history of PH-02D shows sand production and water breakthrough, consistent with pressure depletion. A phased redevelopment strategy is proposed, including a pilot well, infill drilling, and workover with sand control and gas lift. These interventions, supported by analogue benchmarking and dynamic modeling, aim to enhance recovery and extend field life. The study demonstrates the value of integrated reservoir characterization in mature fields and supports its application in similar offshore settings within the Niger Delta Basin.

Keywords:

Seismic, Reservoir, Niger Delta Basin, Stratigraphy, Well logs, Modeling, Compartmentalization

Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Phyllis Ekwerike reports equipment, and statistical analysis were provided by Chevron Nigeria Ltd.

Introduction

Reservoir characterization is a critical component of hydrocarbon exploration and production, particularly in mature fields where optimization of recovery requires a refined understanding of subsurface architecture. In the Niger Delta Basin, one of Africa's most prolific hydrocarbon provinces, complex structural and stratigraphic settings pose significant challenges to accurate reservoir modeling and volume estimation (Doust and Omatsola, 1990; Tuttle et al., 1999). The basin's petroleum system, dominated by the Akata source rocks and Agbada reservoir facies, is characterized by growth faulting, rollover anticlines, and stratigraphic pinch-outs that influence hydrocarbon migration and entrapment (Short and Stauble, 1967; Evamy et al., 1978).

The Phyl Field, located offshore within the middle to late Miocene depobelt of the Niger Delta, was discovered in 1988 and confirmed by subsequent appraisal drilling in 1993. Despite initial production success, the field ceased production in 2020 due to limitations in the existing reservoir model, including poor seismic-well integration, uncertain fluid contacts, and inadequate representation of reservoir heterogeneity. The D-10/Ph-02 reservoir, which is the focus of this study, presents an opportunity for recharacterization using modern seismic and petrophysical techniques to reassess hydrocarbon potential and guide redevelopment.

Recent studies have demonstrated the value of integrating reprocessed 3D seismic data with well logs, biostratigraphy, and production history to improve reservoir delineation and volumetric accuracy (Ogbe et al., 2020; Dada et al., 2023). This multidisciplinary approach enables the identification of bypassed pay zones, refinement of fluid contacts, and evaluation of reservoir quality parameters such as porosity, permeability, and water saturation. In particular, the use of sequence stratigraphy and biostratigraphic markers enhances the correlation of depositional units and supports paleoenvironmental reconstruction (Ajayi, 2022; Haq et al., 1988).

This study aims to recharacterize the D-10/Ph-02 reservoir using an integrated workflow that combines seismic interpretation, petrophysical analysis, stratigraphic correlation, and production performance evaluation. The objectives include updating the structural framework, refining hydrocarbon volume estimates, assessing pressure depletion, and proposing a phased redevelopment strategy. By leveraging modern interpretation techniques and historical production data, the study seeks to optimize recovery and extend the productive life of the Phyl Field.

1. Geological Setting

The Phyl Field is situated in the offshore portion of OML-49, within the eastern Niger Delta Basin (Figure 1), approximately 5 km north of the Malta Field and 5 km east of the Jakpa Field. It lies within the middle to late Miocene depobelt, a structurally complex zone characterized by growth faulting, canyon incision, and stratigraphic compartmentalization. The Niger Delta Basin itself is a prolific hydrocarbon province formed during the Late Cretaceous to Recent, as a result of the rifting and subsequent drifting of the South American and African plates (Burke et al., 1971; Doust and Omatsola, 1990).

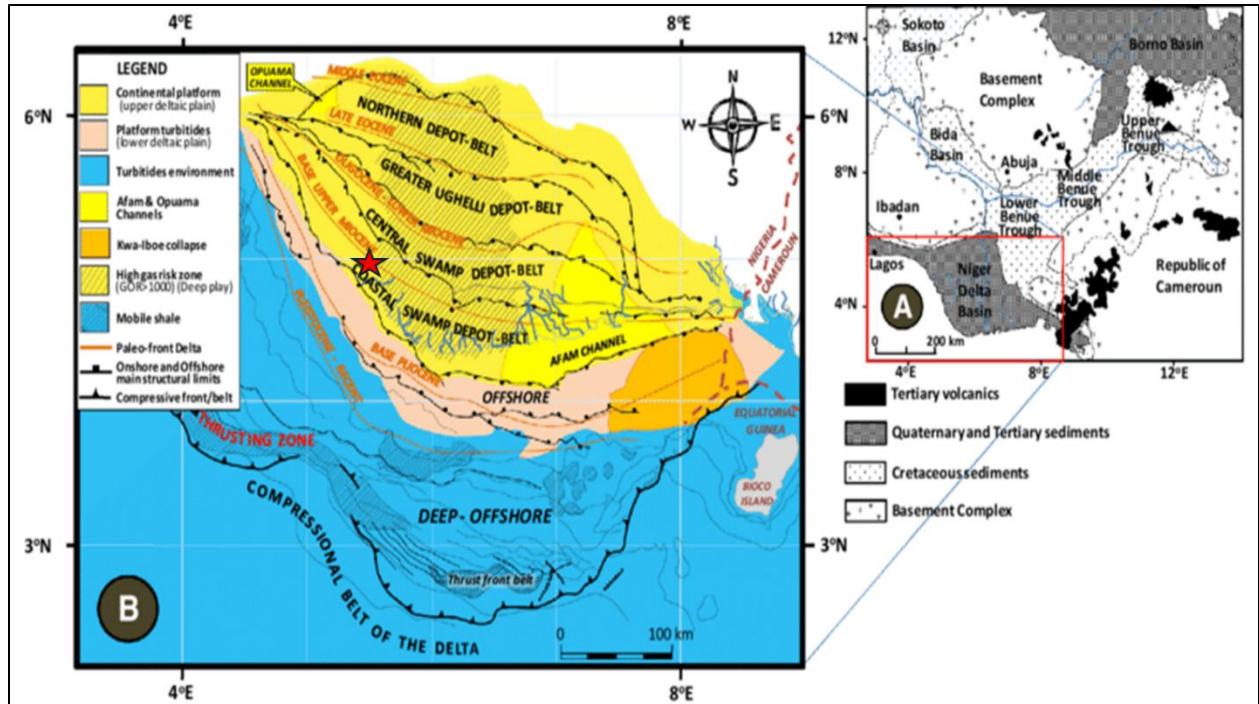


Fig. 1. (A) Geologic map of Nigeria showing the location of the Niger Delta Basin (modified from Ebong et al., 2020). (B) Sectional map of the Niger Delta depobelts and structural limits with the red oval shape showing the study area in the Niger Delta depobelts (modified from Doust and Omatsola, 1990)

The basin comprises three primary lithostratigraphic units: the Akata Formation (deep marine shales), the Agbada Formation (paralic sand-shale sequences), and the Benin Formation (continental sands) (Figure 2). The Agbada Formation, which hosts the D-10/Ph-02 reservoir, is composed of interbedded fluvio-deltaic sandstones and marine shales deposited in a regressive sequence. These sediments were influenced by high sediment supply, eustatic sea-level fluctuations, and syn-sedimentary tectonics (Evamy et al., 1978; Tuttle et al., 1999).

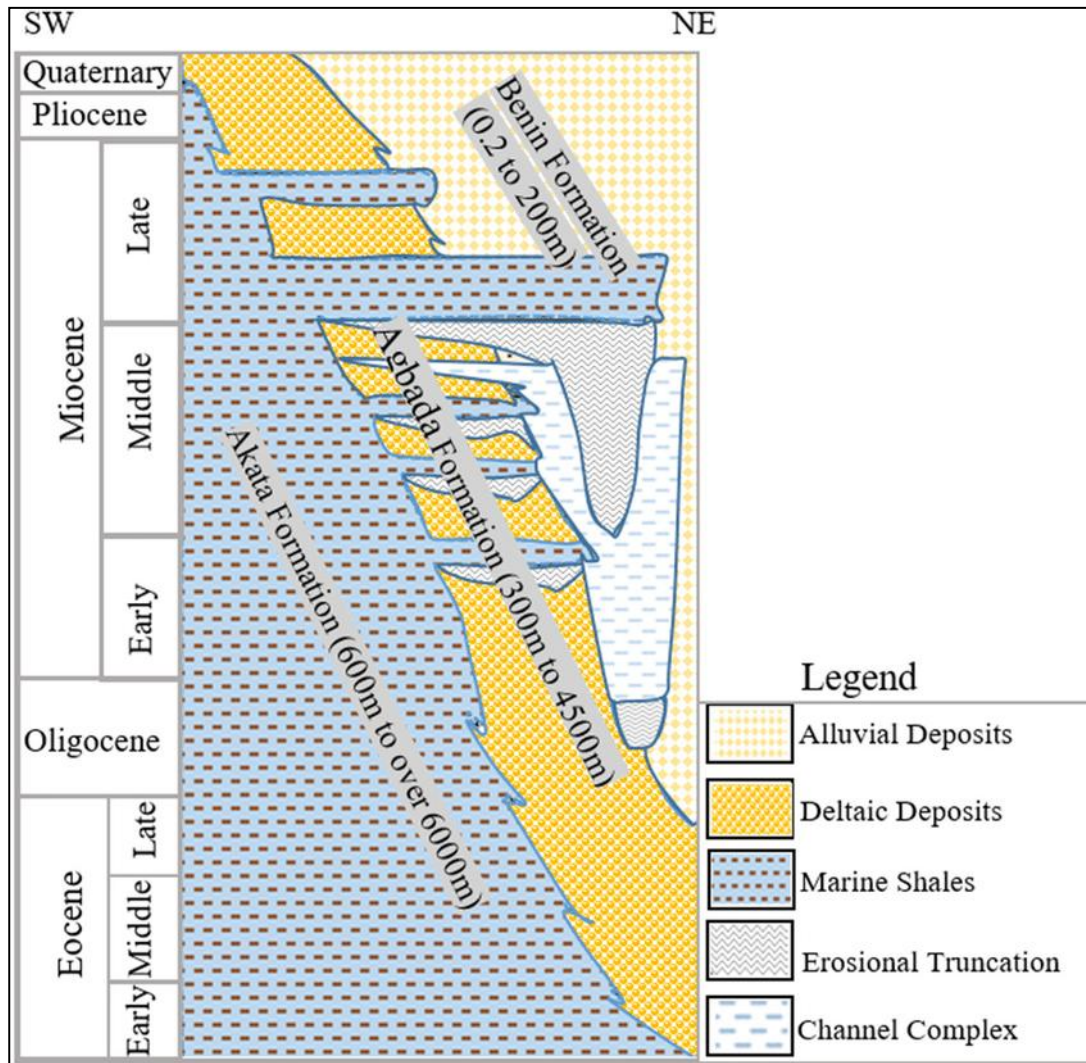


Fig. 2. Stratigraphic column showing the three formations of Niger delta (modified from Doust and Omatsola, 1990; Shannon and Naylor, 1989)

Structurally, the Phyl Field is bounded by the Phyl structure-building fault to the east, the Japa fault to the west, and a Miocene mud-filled canyon to the northwest (Figure 3). The field exhibits a combination of structural and stratigraphic traps, including rollover anticlines, fault-assisted closures, and canyon truncation features.

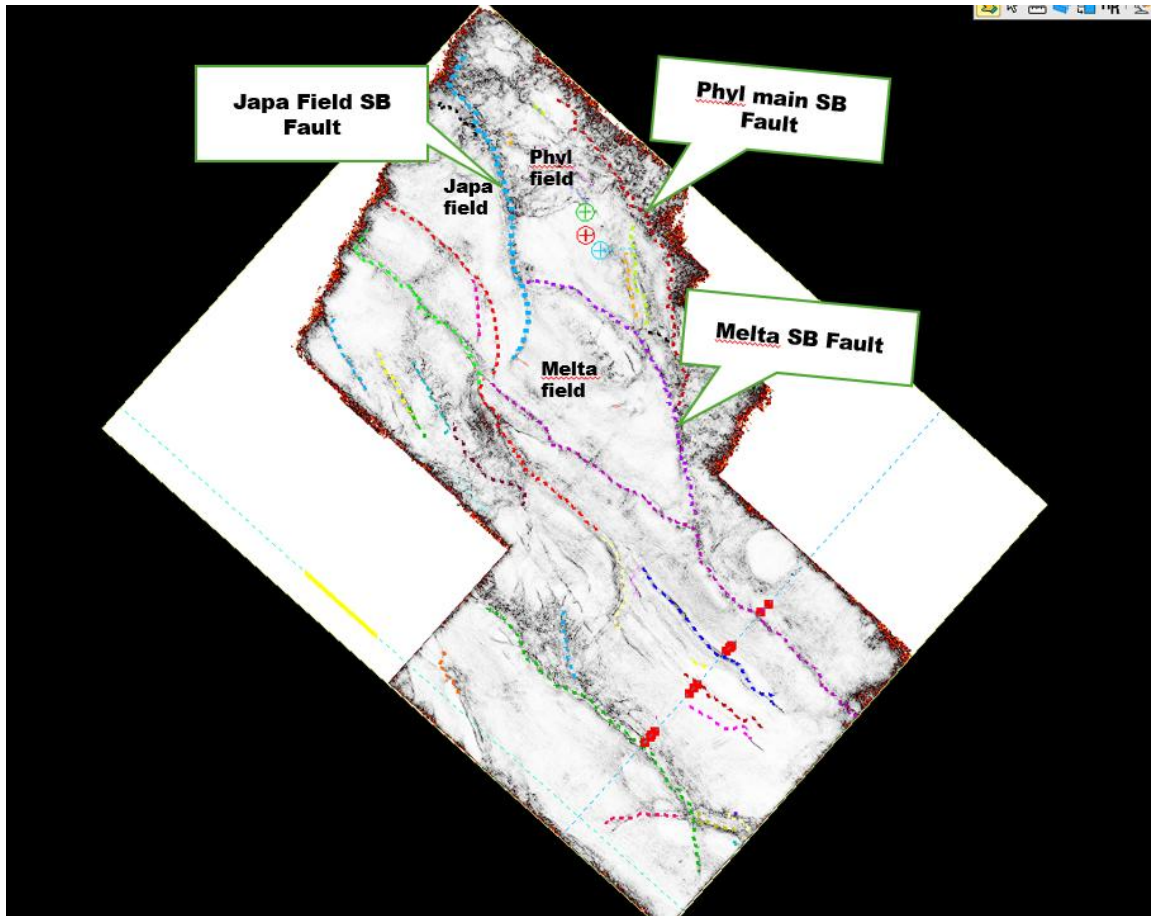


Fig. 3. Time Slice -1500ms showing the field bounding faults and structural architecture

The D-10 reservoir is interpreted as a three-way dip closure truncated by a canyon system, forming a combination trap with strong hydrocarbon retention potential. Biostratigraphic analysis indicates that the reservoir sands were deposited in a coastal deltaic to inner neritic environment during the Late Miocene (Figure 4). The presence of *Globigerinoides trilobus* and other neritic microfossils supports this deduction. Sequence stratigraphic markers, including Maximum Flooding Surfaces and Transgressive Surfaces, were identified and correlated across wells, aiding in the reconstruction of depositional history and reservoir continuity.

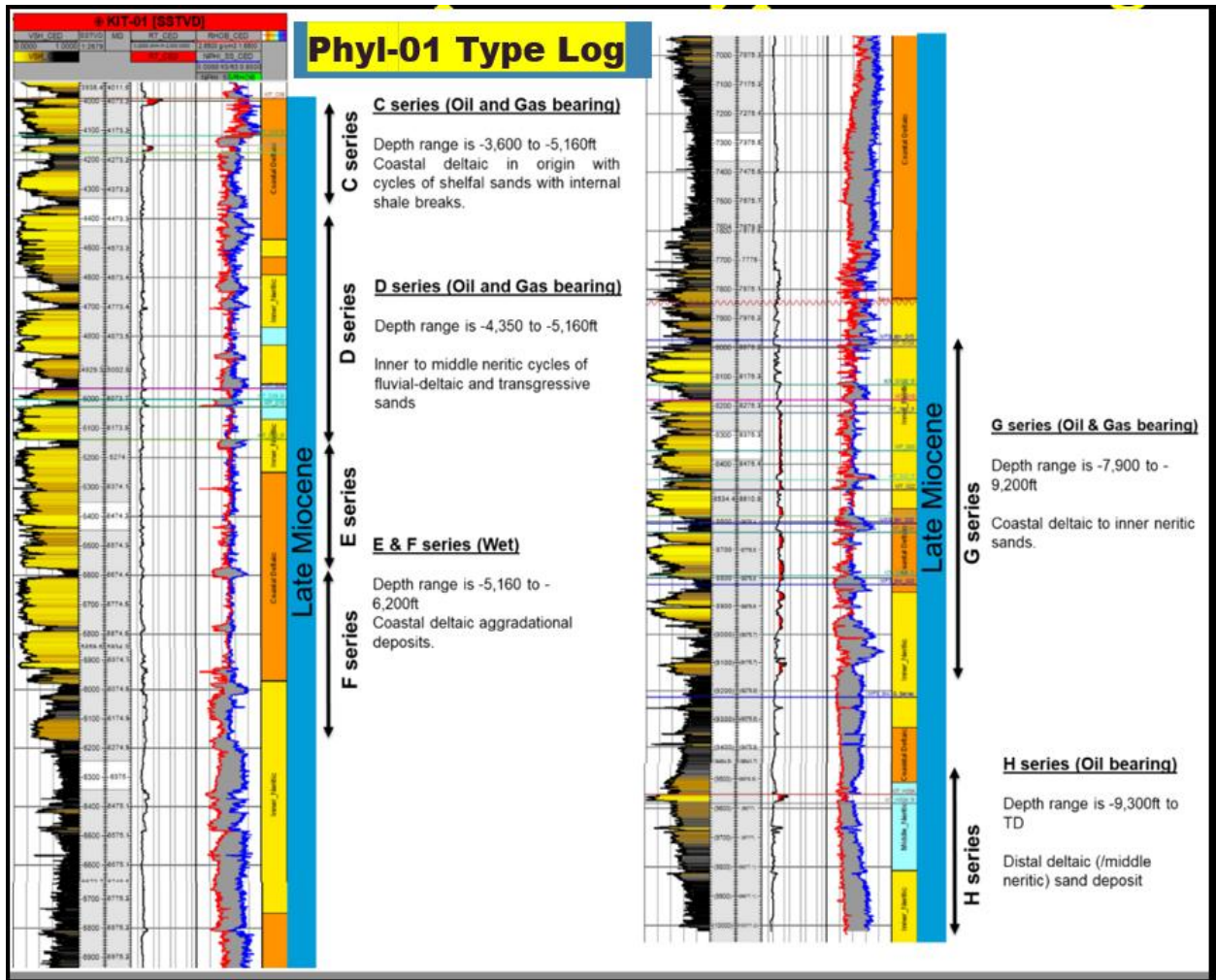


Fig. 4. Composite Type Well Log for The Phyl Field

The regional petroleum system is defined by the Akata-Agbada system, with the Akata shales serving as the primary source rock and the Agbada sandstones functioning as reservoirs (Figures 5 and 6). Migration occurs along fault planes and stratigraphic pinch-outs, with sealing provided by intra-formational marine shales and canyon fills. The Phyl Field's structural complexity and stratigraphic variability underscore the importance of integrated reservoir characterization for accurate hydrocarbon volume estimation and field redevelopment planning.

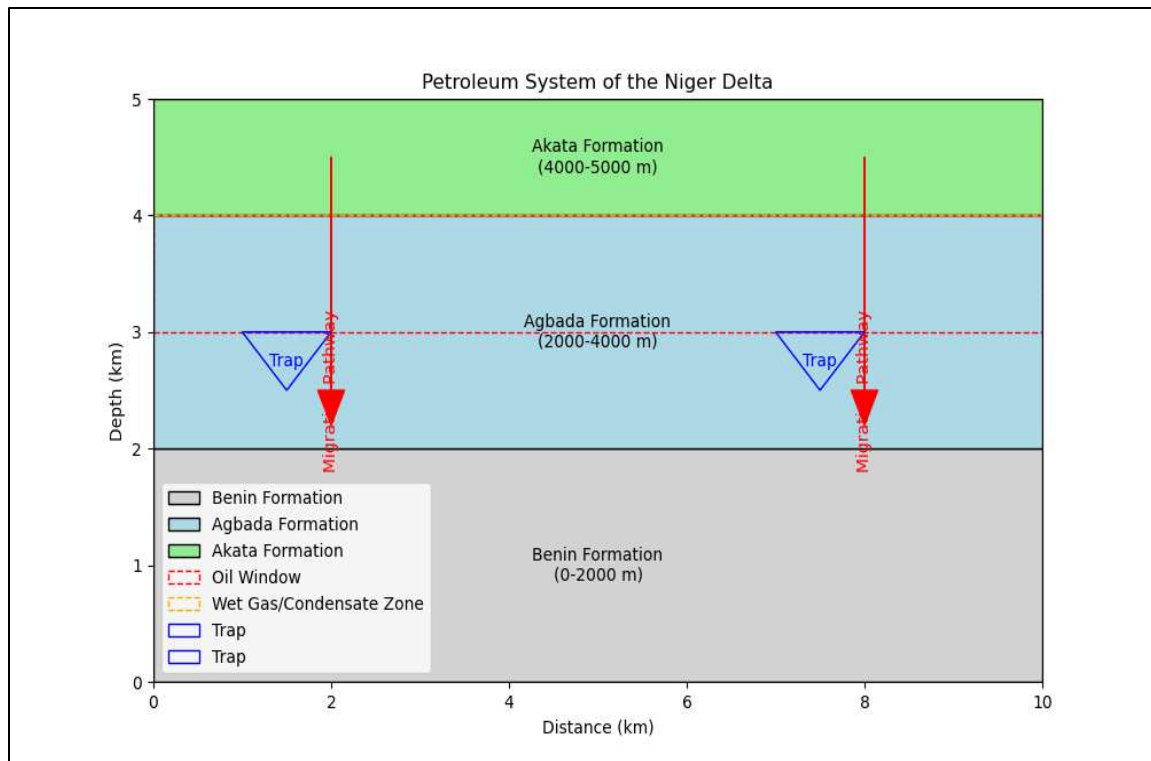


Fig. 5. Petroleum system diagram of the Niger Delta.

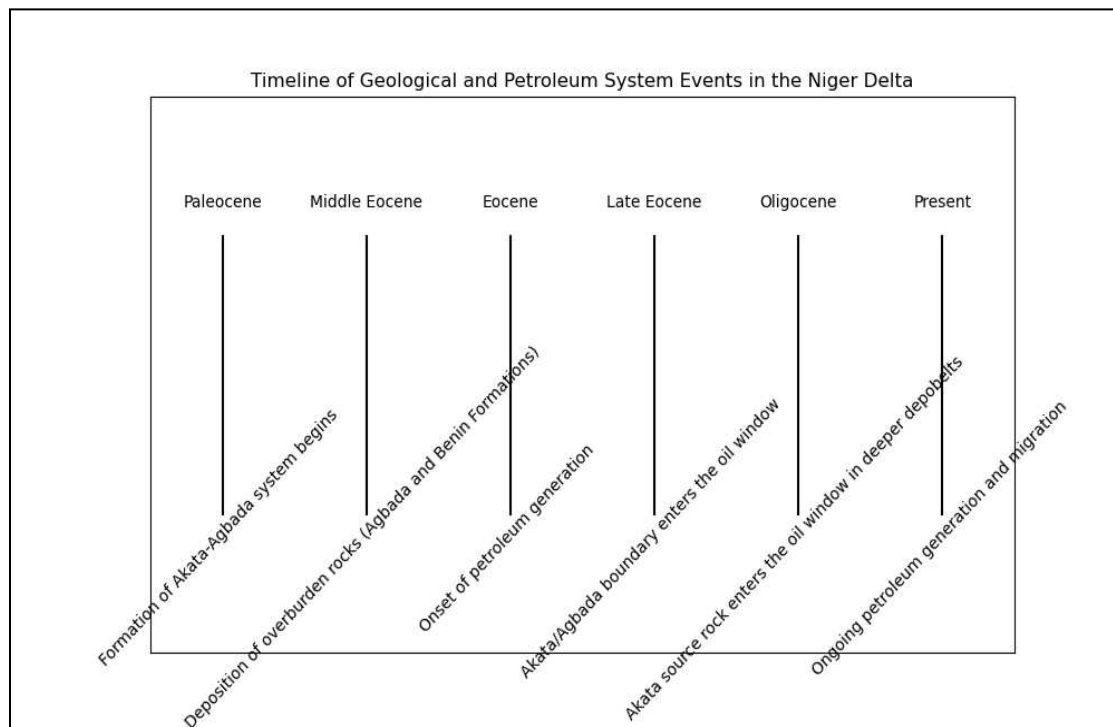


Fig. 6. Timeline of geological and petroleum system events in the Niger Delta.

2. Methodology

The dataset comprised composite well logs from PH-01, PH-02, and PH-03, including Gamma Ray, Resistivity, Density, Neutron, and Sonic logs. A reprocessed 3D seismic volume featuring zero-phase reflectivity and prestack imaging was employed, alongside an active velocity model for time-depth conversion. Production history and pressure data spanning the period from 1994 to 2020 were analyzed to inform reservoir performance and fluid contact estimation.

Variance edge attributes were used to enhance fault and horizon visibility. Time structure maps were generated for the D10/PH-02 reservoir, followed by depth conversion using an active velocity model. This ensured accurate volumetric analysis and supported the structural framework used in reserve estimation. Faults were interpreted using structural attributes and increment-based picking. Horizon mapping focused on four key reflectors, two of which corresponded to hydrocarbon-bearing sands. Mapping was anchored at PH-02 and extended laterally using loop tie methods. The structural complexity of the Phyl Field, including listric growth faults and synthetic/antithetic fault systems, was carefully analyzed to understand hydrocarbon migration and trapping mechanisms.

Supplementary data was sourced from Field Development Plans, Petrophysical data sheets, and End of Well reports. All datasets were integrated within Petrel software to facilitate interpretation, map based volumetric estimation, and cross-disciplinary analysis. This integration ensured consistency across platforms and provided a robust foundation for geological, geophysical, and petrophysical evaluations throughout the study. Petrophysical logs were analyzed using Petrel software to derive porosity, permeability, and fluid saturation.

Lithostratigraphic correlation was performed using Gamma Ray, Resistivity, and Neutron/Density logs to delineate reservoir tops and bases (Figures 7 and 8). Biostratigraphic analysis (Table1) were incorporated to support stratigraphic correlation and depositional environment analysis. The proximity of wells, all within a 5 km radius, justified this method and yielded insights into reservoir continuity, aiding in modeling and well placement (Figure 9).

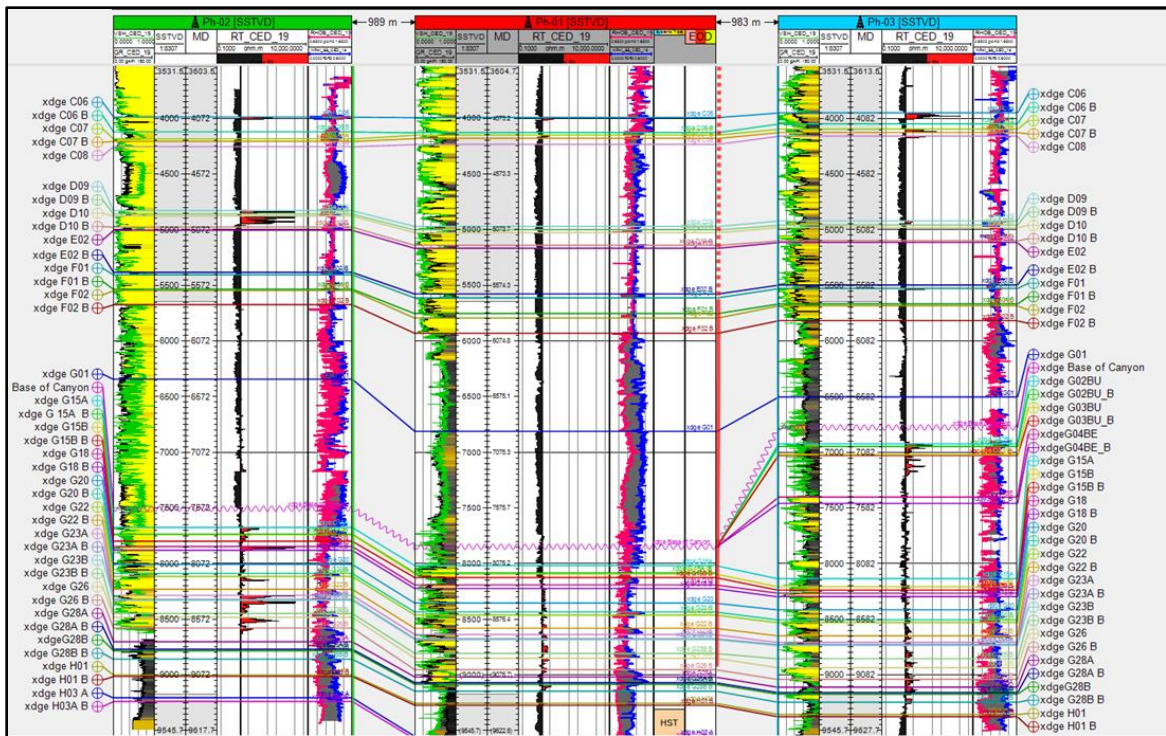


Fig. 7. Well Log Correlative Analysis of the Phyl Field

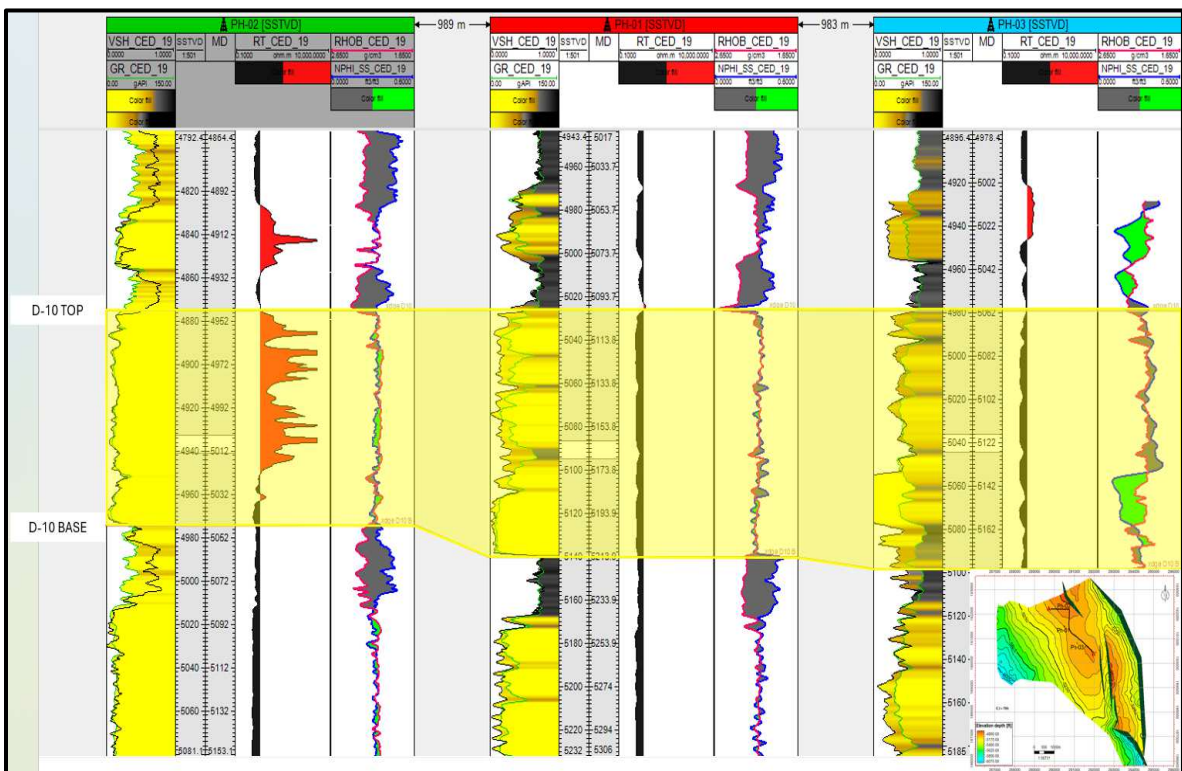


Fig. 8. Stratigraphic Correlation Section: D-10/Ph-02 Reservoir with insert Depth map

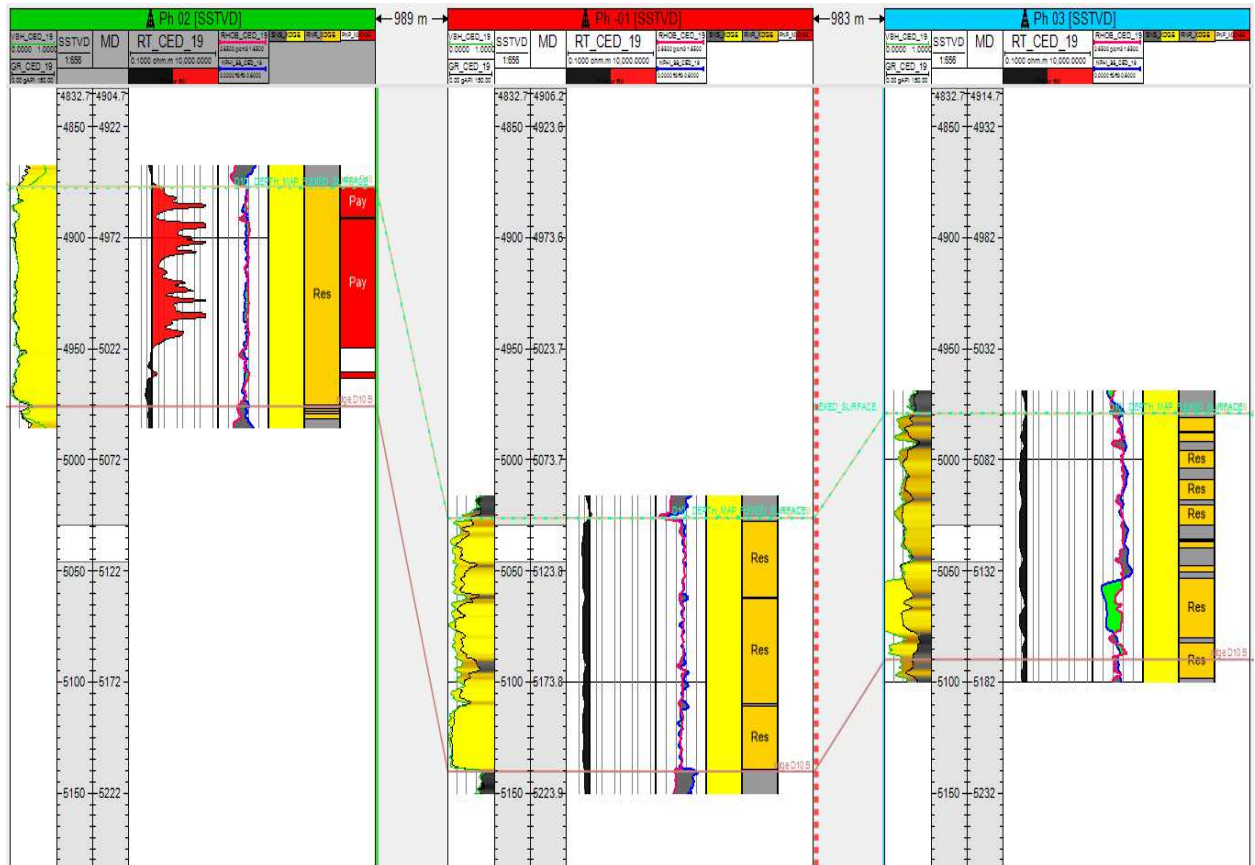


Fig. 9. Well Log Structural Cross Section of D10/Ph-02 Reservoir

Key reservoir properties were computed, including Shale Volume, Porosity, and Water Saturation, using Archie's Equation. Cutoffs were applied to classify intervals into Sand/No Sand, Reservoir/Non-Reservoir, and Pay/Non-Pay zones. These classifications aided the calculation of Net-to-Gross ratio, average porosity, and saturation metrics, which were used to evaluate reservoir quality and distribution.

Biostratigraphic data, integrated with wireline logs, facilitated the identification of key stratigraphic surfaces and depositional environments. The section penetrated a Late Miocene succession within the Agbada Formation, characterized by alternating sand and shale units. Correlation with global eustatic cycles, particularly those outlined by Haq et al. (1988), provided temporal context and supported the sequence stratigraphic framework. Gamma Ray log motifs were interpreted to infer depositional settings ranging from fluvial channels to deltaic environments (Emery and Myers, 1996). Facies analysis supported reservoir characterization, heterogeneity assessment, and zonation. The integration of biostratigraphy and log signatures enabled identification of sequence boundaries, maximum flooding surfaces, and transgressive surfaces, enhancing the understanding of stratigraphic architecture.

Seismic reflectors were correlated with well log markers to ensure consistency between seismic and geological interpretations. Velocity modeling enabled time-to-depth conversion,

enhancing structural accuracy. Petrel software facilitated the integration of seismic, well log, and biostratigraphic data into a unified subsurface model, allowing for a coherent interpretation of the field's stratigraphy and structure.

Table 1: Phyl-01 Biostratigraphic Analysis showing Interpreted MFS

Depth MD (ft)	Event type	Fossil marker(s)	Age (Ma)
4770	MFS	Top <i>Helicosphaera amplierperta</i>	MFS-15.60 Ma
6690	MFS	Peak faunal abundance	MFS-16.86 Ma
7880	MFS	Peak faunal abundance	MFS-18.00 Ma
9570	MFS	LDO <i>Globigerinoides altiaperturus</i>	MFS-19.10 Ma

3.1 Petrophysical Properties

Mapped properties including Gross Thickness, Net-to-Gross ratio, Porosity, were interpolated geostatistically, and water saturation (S_w) was estimated using Archie's Equation, suitable for clean sandstone reservoirs:

$$S_w = (a * R_w / (\phi^m * R_t))^{(1/n)}$$

Where:

- $a = 1$ (tortuosity factor)
- $m = 2$ (cementation exponent)
- $n = 2$ (saturation exponent)
- R_w : Formation water resistivity (from well test or regional data)
- R_t : True formation resistivity (from resistivity logs)
- ϕ : Porosity (from density-neutron logs)

This computation was implemented in Petrel, and the resulting S_w values were used to derive hydrocarbon saturation ($S_h = 1 - S_w$), critical for identifying pay zones and estimating reserves.

Field-specific cutoffs were applied to classify the reservoir intervals into:

- Sand / No Sand (SNS)
- Reservoir / Non-Reservoir (RNR)
- Pay / Non-Pay (PNP)

Petrophysical cutoffs:

- $V_{sh} \leq 50\%$
- $Porosity \geq 12\%$
- $S_w \leq 70\%$

Spatial distribution of reservoir quality was visualized through Net-to-Gross, Porosity, and Water Saturation maps. Fluid contacts were estimated using log signatures and pressure data, guiding reserve estimation and development planning.

A revised Oil-Water Contact was proposed based on reinterpretation of resistivity and density logs, cross-well correlations, and production trends. The resistivity drop observed at -4964 ft was attributed to lithological variation rather than fluid transition, prompting a shallower contact depth. Material balance and early water breakthrough patterns further supported the revision, enhancing the accuracy of reserve estimates and production forecasting.

3.2 Volumetric Analysis

The volumetric analysis was performed from standard Map-based volumetric estimation, incorporating mapped area, net pay thickness, porosity, and saturation values. The updated estimates reflect improved reservoir understanding and more realistic production expectations.

Stock tank oil in place (STOIP) was calculated using:

$$\text{STOIP} = (7758 * A * h * \phi * (1 - S_w)) / (B_o)$$

where:

- *A*: area (acres)
- *h*: net pay thickness (ft)
- ϕ : porosity
- *S_w*: water saturation
- *B_o*: formation volume factor

Volumetric calculations employed the STOIP equation, integrating structural and petrophysical data to estimate reserves. The Petrel map-based volumetric tool was used to define pay zones and compute hydrocarbon volumes, providing a quantitative basis for field development planning. Recovery factor derived from historical production and EUR estimates.

Reserves are expected to be partially drained by the currently active completion PH-02D, while a new well should be drilled to ensure maximum recovery and efficient drainage of the remaining reserves.

3. Results and discussions

3.1 Structural Framework and Reservoir Architecture

Seismic interpretation of the Phyl Field as shown in Figures 11, 12 and 13 reveals a structurally complex setting dominated by listric growth faults, synthetic and antithetic fault systems, and Miocene mud-filled canyons. These features have compartmentalized the D-10/Ph-02 reservoir into discrete fault blocks, influencing hydrocarbon distribution and reservoir continuity. The primary structure is a three-way dip closure bounded by the Phyl structure-building fault to the east, the Japa fault to the west, and a canyon truncation to the northwest. This configuration forms a combination trap with both structural and stratigraphic components, consistent with regional trapping styles in the Niger Delta (Doust and Omatsola, 1990; Ogbe et al., 2020). The D10 trap geometry and configuration represent a combination trap, with a strong structural component particularly evident in the southeast. A prominent 3-way dip closure, formed by a rollover anticline in the northeast, is truncated by the northeast-southwest trending Miocene canyon edge. This structural configuration provides a robust trapping mechanism for the D10 reservoir, enhancing

hydrocarbon entrapment as hydrocarbon filled towards the crest of the structure. The structure is saddle separated into two pools, the northern high in Phyl and southern high below Melta field.

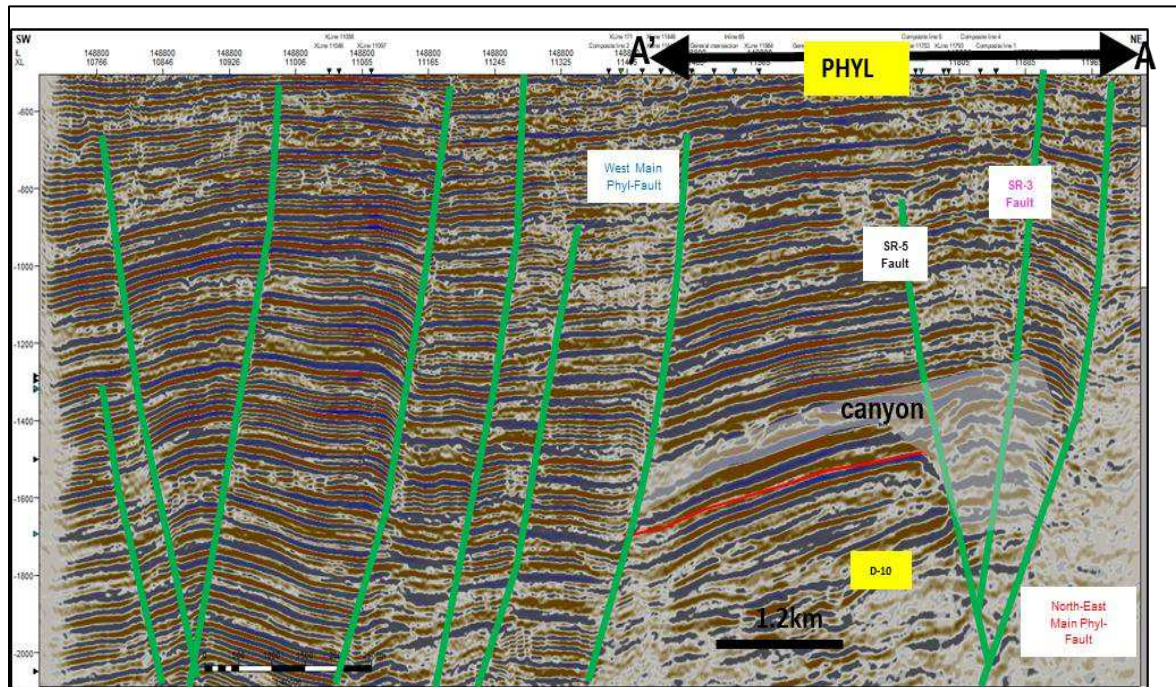


Fig. 11. Seismic Dip Line Section: Inline 148800 in the northern part of the field

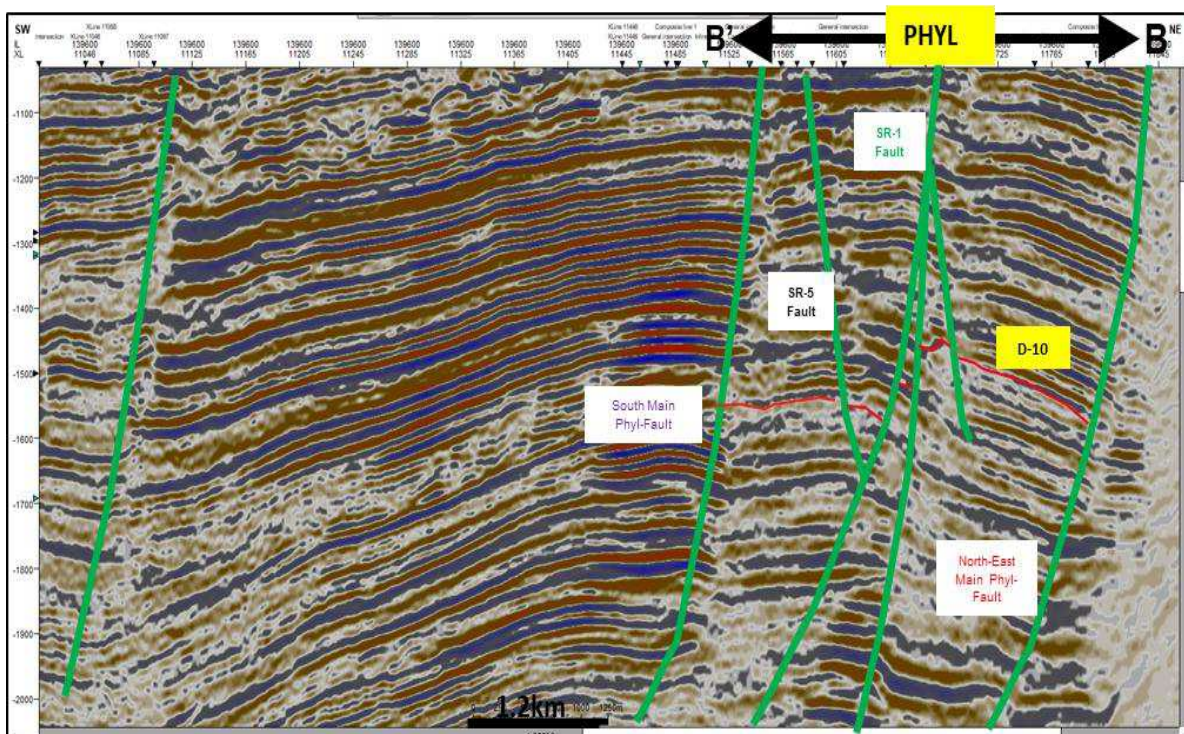


Fig. 12. Seismic Dip Line Section: Inline 139600 in the southern part of the field

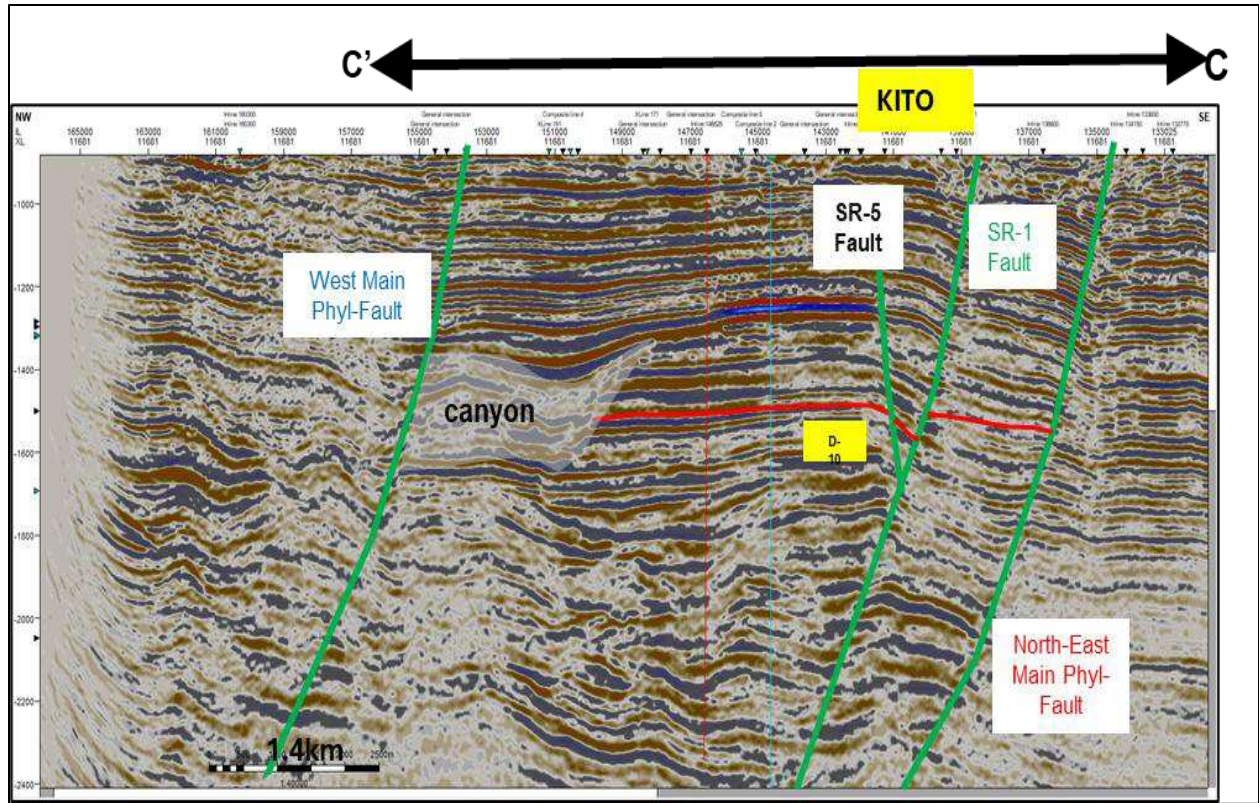


Fig. 13. Seismic Strike line Section (Cross line 11681) showing the mapped D10/PH-02 Reservoir from North to the South of the Phyl Field

3.1.1 Time Structure Map

The time structure map, as illustrated in Figure 14, was instrumental in visualizing the subsurface architecture, revealing the geometry and orientation of key geological features such as fault blocks, structural highs, and depressions. Through map brought to light the spatial relationships between these features, offering a clearer understanding of the tectonic framework of the region. Beyond mere visualization, the map served as a powerful interpretive tool. The contour patterns provided critical clues about the presence of potential hydrocarbon traps, faulted zones, and stratigraphic closures. These insights guided the identification of promising drilling targets and informed decisions about well placement and reservoir modeling. Additionally, the the time structure map laid the groundwork for a more refined and confident interpretation of the subsurface, bridging the gap between raw seismic data and actionable geological understanding.

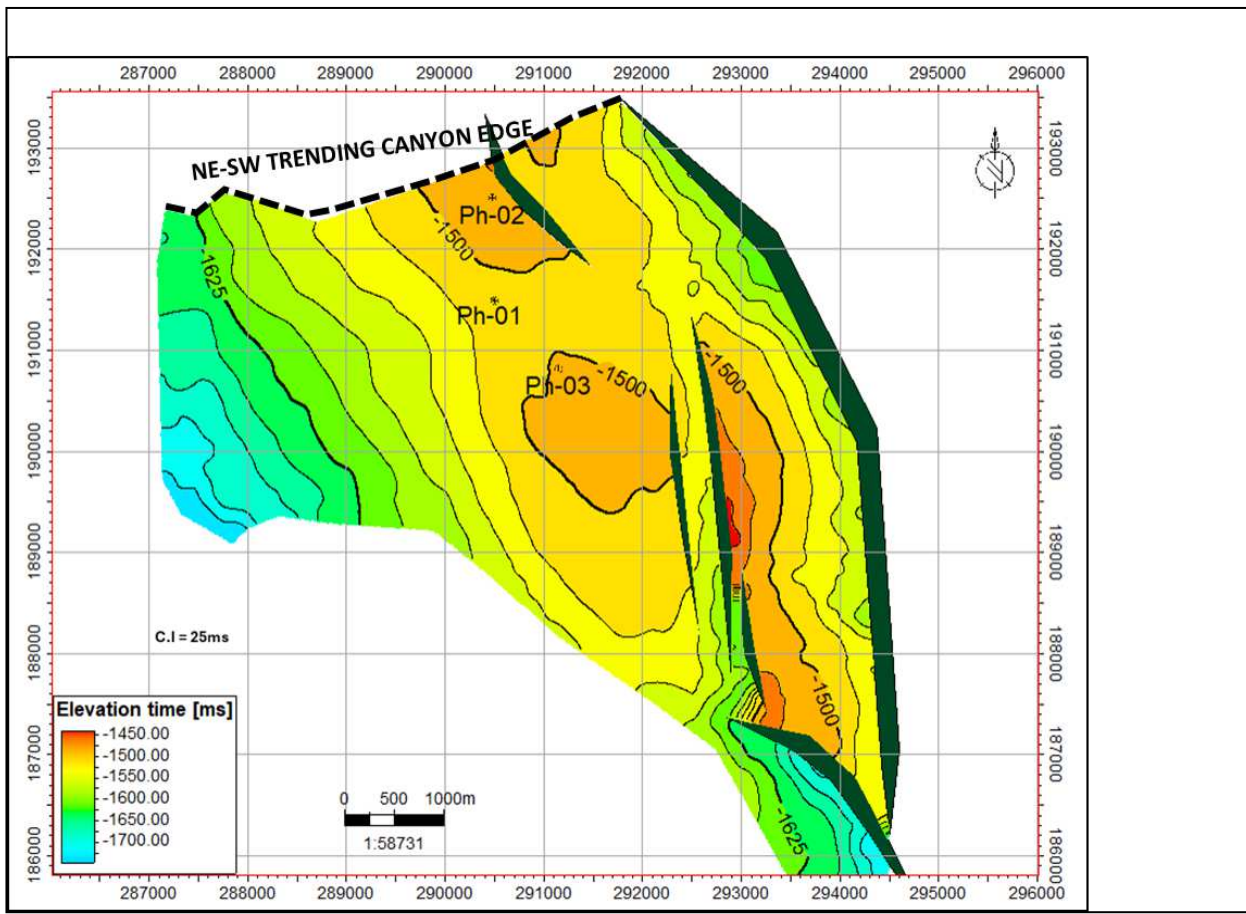


Fig. 14. Time Structure Map of D10/PH-02 Reservoir of the Phyl Field

4.1.2 Time-to-Depth Conversion and Structural Validation

Following the generation of the time structure map, the interpreted seismic features namely fault sticks and stratigraphic horizons converted from the time domain to the depth domain. This transformation was achieved using an active average velocity model (V_{avg}). The velocity model, calibrated with well data and regional trends, ensured that the depth conversion was both geologically consistent and technically accurate. The resulting depth structure map, shown in Figure 15, preserved the integrity of the original interpretation. Notably, the geometry of the D10 horizon remained consistent across both domains, with a distinct saddle feature separating two prominent structural highs. This continuity between time and depth domains reinforced the reliability of the velocity model and validated the seismic interpretation. Furthermore, the depth map retained essential structural elements such as fault geometries, closures, and trap configurations, all of which were initially observed in the time map. Figure 15 further illustrates this consistency, confirming that the key features were not distorted during the conversion process. This alignment between time-based and depth-based representations is crucial for accurate reservoir characterization and underscores the robustness of the structural model.

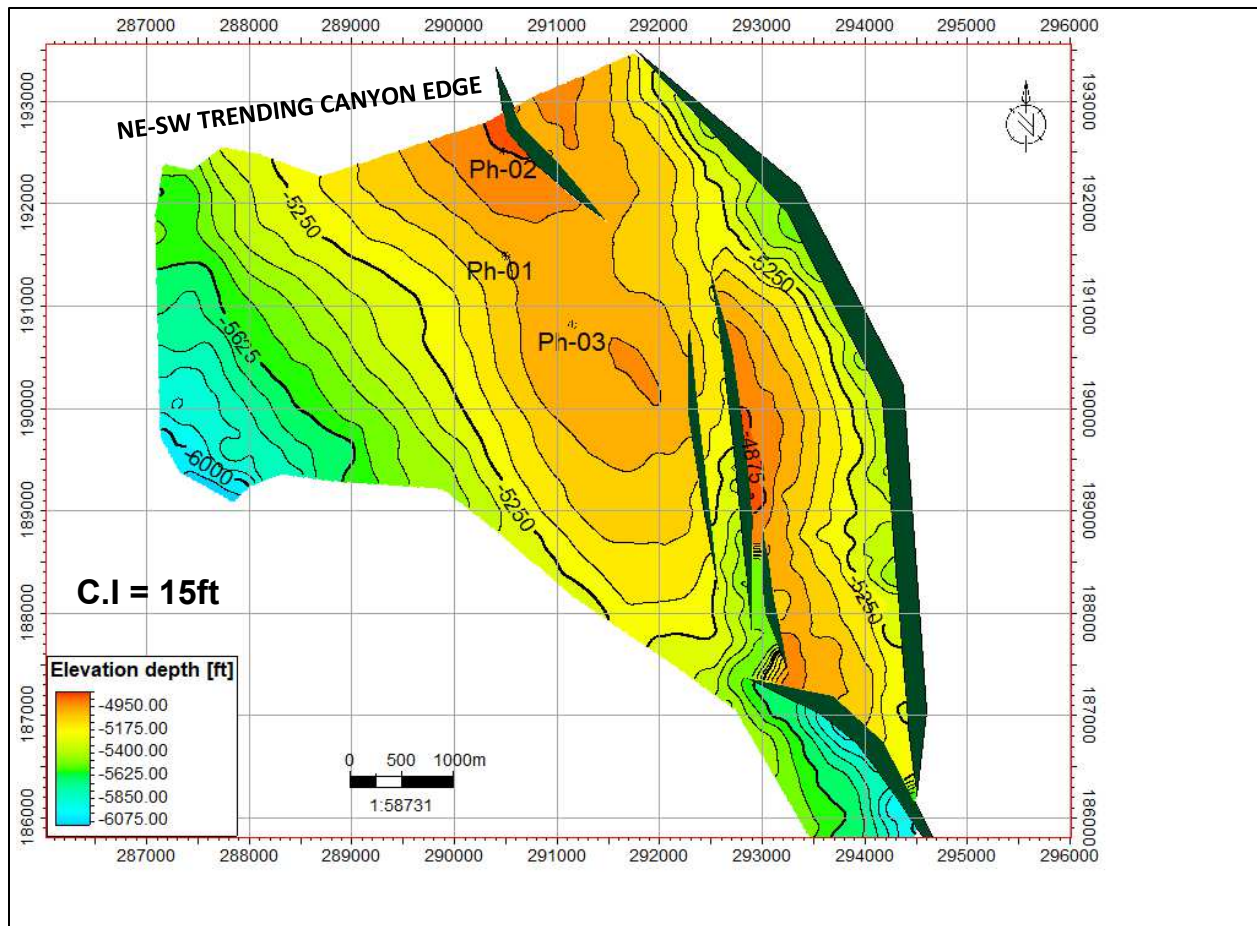


Fig. 15. Depth Map of D10/PH-02 Reservoir of the Phyl Field

3.2 Reservoir Quality and Petrophysical Evaluation

Petrophysical evaluation across wells PH-01, PH-02, and PH-03 confirms that the D-10/PH-02 interval represents a high-quality reservoir with excellent characteristics for hydrocarbon storage and production. The integration of well log data with seismic-derived property maps has enabled a robust interpretation of reservoir geometry, quality, and distribution. Figures 16, 17 and 18 play a critical role in validating these interpretations and guiding development decisions.

4.2.1 Gross Thickness Map

The gross thickness map of the D-10/PH-02 reservoir, presented in Figure 16, reveals a laterally extensive and well-developed sand package. The thickness distribution is generally uniform, with a noticeable increase toward the southeast and a gradual thinning toward the northwest. This trend suggests a depositional gradient likely influenced by sediment transport direction and paleogeographic controls. The map provides essential input for volumetric calculations and confirms the continuity of the reservoir across the field. Figure 16 visually reinforces the interpretation by highlighting the spatial variation in thickness, which is critical for identifying zones of maximum reservoir development and for planning optimal well trajectories.

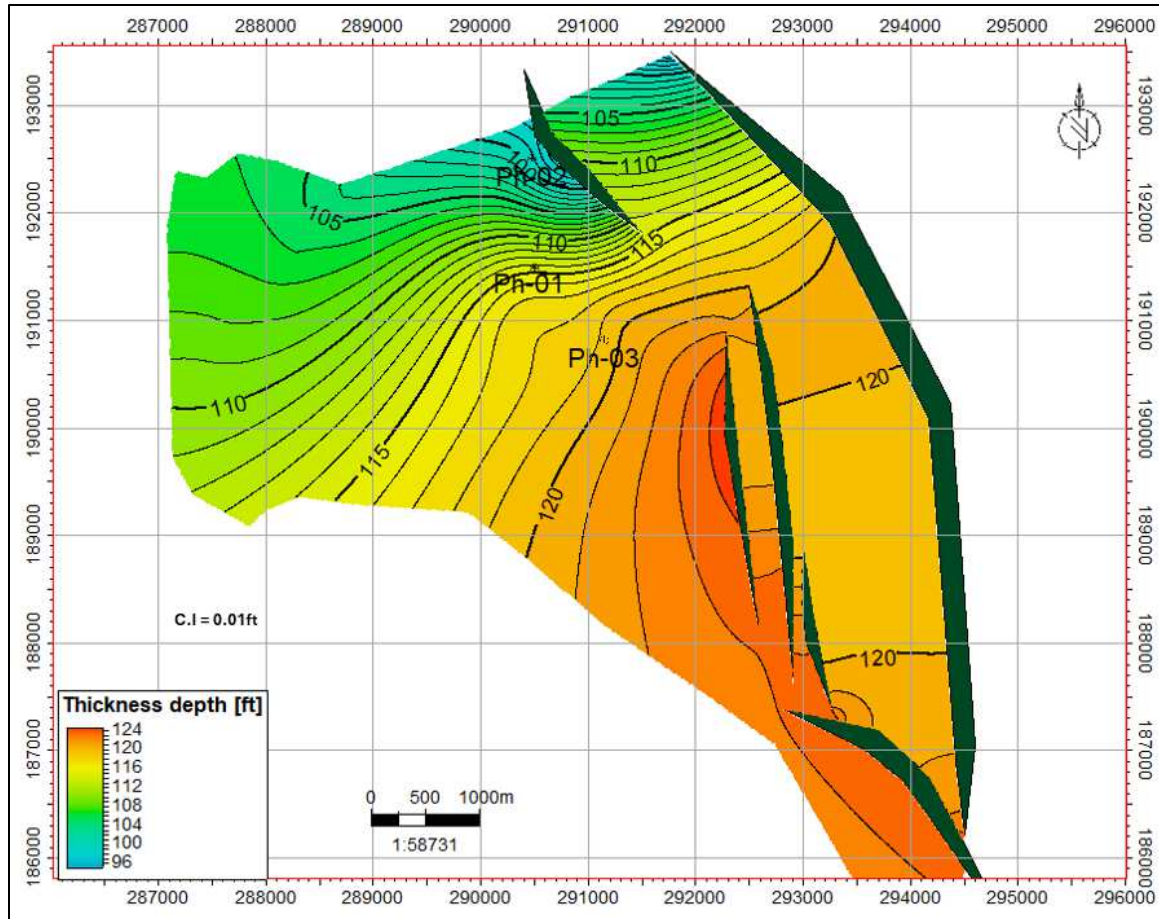


Fig. 16. Gross thickness map for D10/Ph-02 Reservoir

4.2.2 Porosity Map

Figure 17 shows the porosity distribution within the D-10/PH-02 reservoir, showing values ranging from 29% to 31%. The highest porosity zones are concentrated in the northern region, with a gradual decrease toward the southeast. This spatial trend aligns closely with the Net-to-Gross distribution shown in Figure 18, reinforcing the consistency of the petrophysical interpretation. High porosity values indicate a strong capacity for hydrocarbon storage, and when combined with favorable permeability and low water saturation, they suggest zones of high productivity potential. The porosity map in Figure 17 is instrumental in identifying sweet spots within the reservoir and supports both static modeling and dynamic simulation efforts. It also informs well placement strategies by delineating areas with optimal reservoir properties.

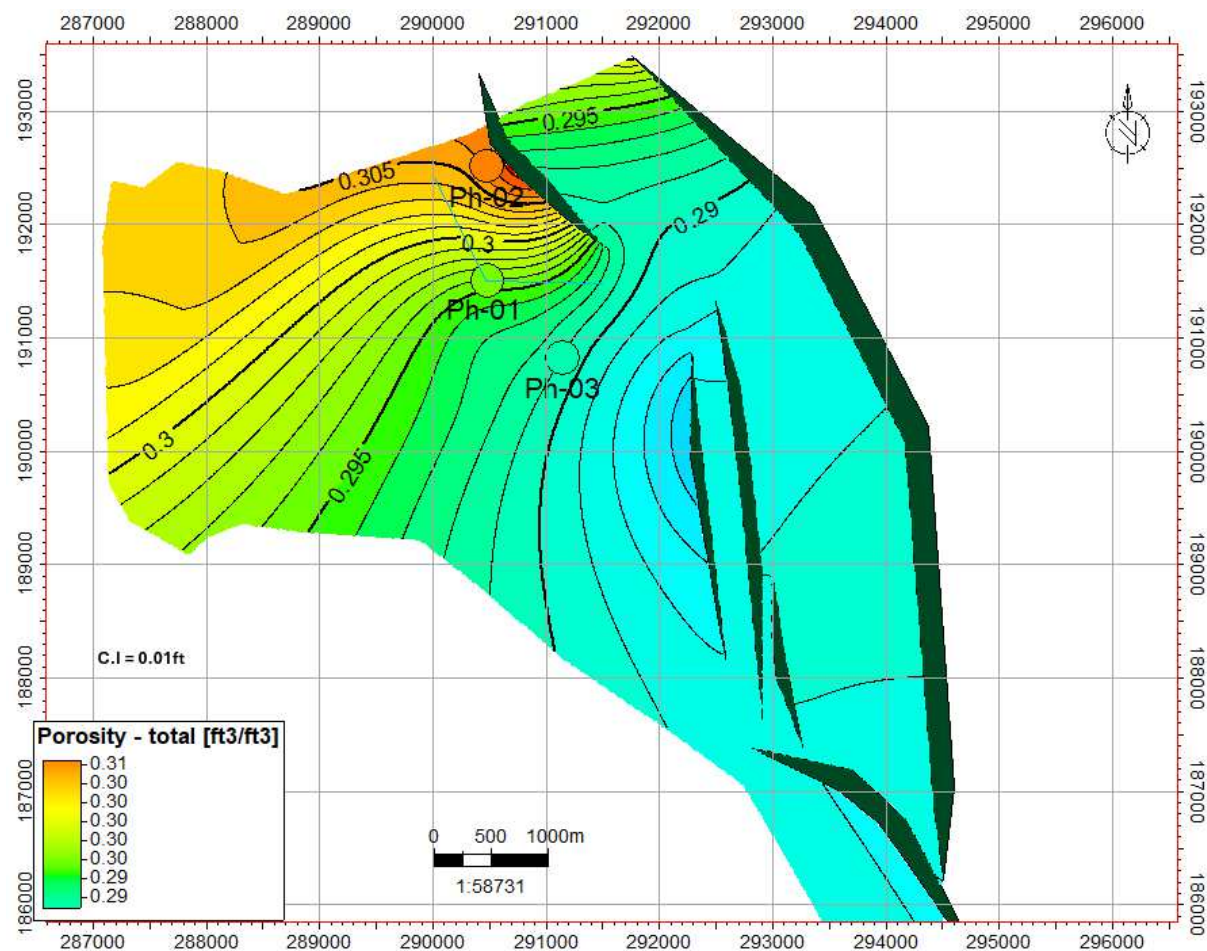


Fig. 17. Porosity map for D10/Ph-02 Reservoir

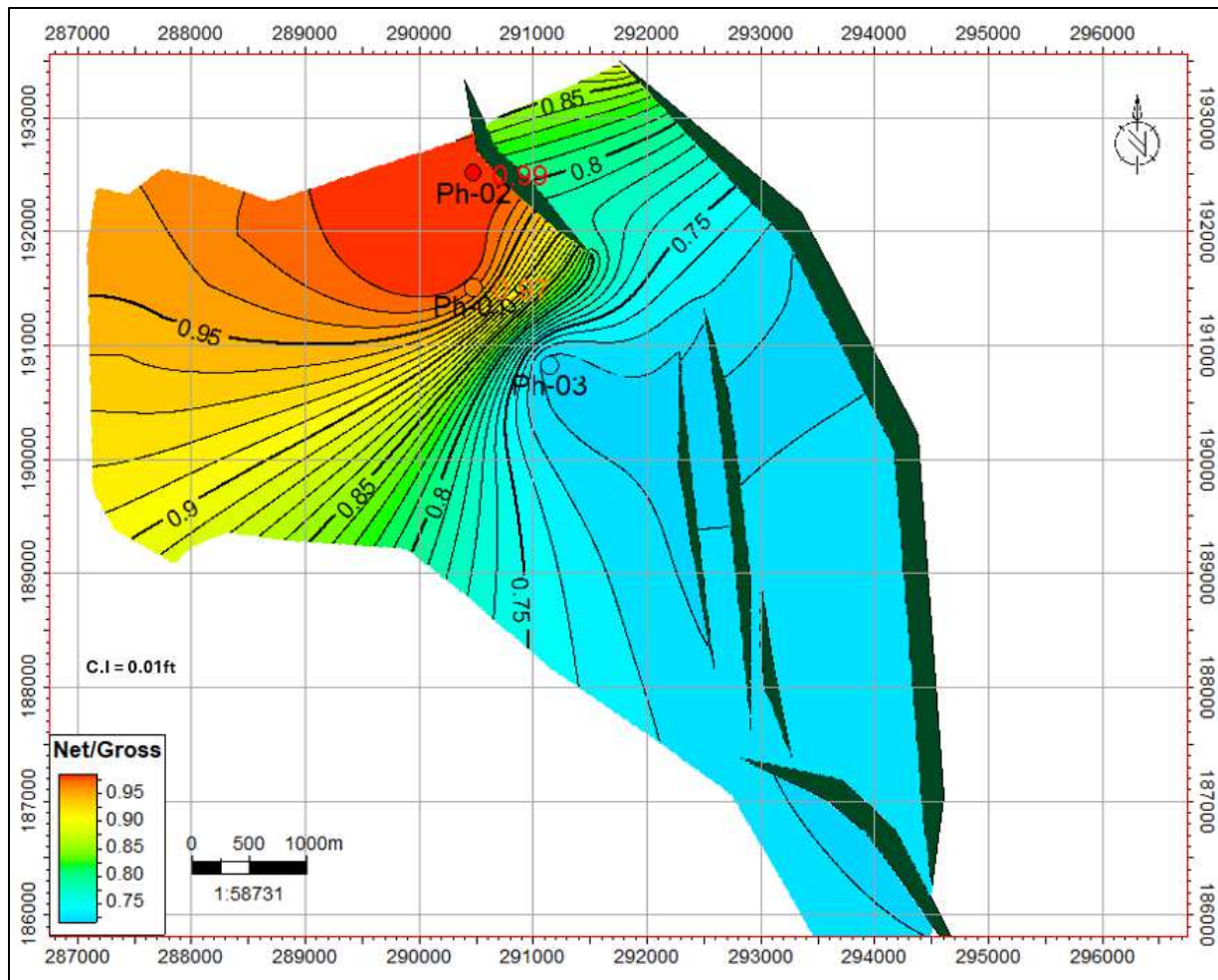


Fig. 18. Net-to-Gross map for D10/Ph-02 Reservoir

4.2.3 Net-to-Gross (NTG) Map

The NTG map, shown in Figure 18, further validates the reservoir's quality, with values ranging from 75% to 100%. These high NTG values indicate that a substantial portion of the gross interval consists of clean, reservoir-grade sandstone with minimal shale content. The spatial distribution reveals a clear trend: higher NTG values dominate the northwestern part of the reservoir and decrease toward the southeast. This pattern mirrors the porosity distribution observed in Figure 17 and suggests a more favorable depositional environment in the northern region. Figure 18 is particularly valuable in quantifying the proportion of net reservoir thickness and in confirming the internal consistency of the reservoir model. Its alignment with other petrophysical maps enhances confidence in the interpretation and supports the identification of optimal zones for development and production.

4.2.4 Water Saturation: Averaging 23%

Water saturation (S_w) within the pay zones was calculated using standard cut-offs $V_{sh} \leq 50\%$, porosity $\geq 12\%$, and $S_w \leq 70\%$ to isolate intervals with commercial hydrocarbon potential. The resulting average S_w value of 23% indicates high hydrocarbon saturation and supports favorable reservoir performance. A spatial water saturation map (Figure 19) was generated to visualize S_w distribution, and although not explicitly shown in the figures referenced, its

integration with Figures 17 and 18 provides a comprehensive view of reservoir quality. The low Sw values, when interpreted alongside high porosity and NTG, confirm the presence of clean, laterally extensive sandstone bodies with minimal argillaceous interference. Lithofacies analysis indicates that the reservoir is dominated by fluvial-deltaic deposits, including blocky and fining-upward sequences interpreted as stacked channel sandstones and shoreface deposits. These facies are consistent with inner to middle neritic environments, a conclusion supported by biostratigraphic markers such as *Globigerinoides trilobus* (Ajayi, 2022), which further validate the depositional model and enhance confidence in the reservoir's development potential.

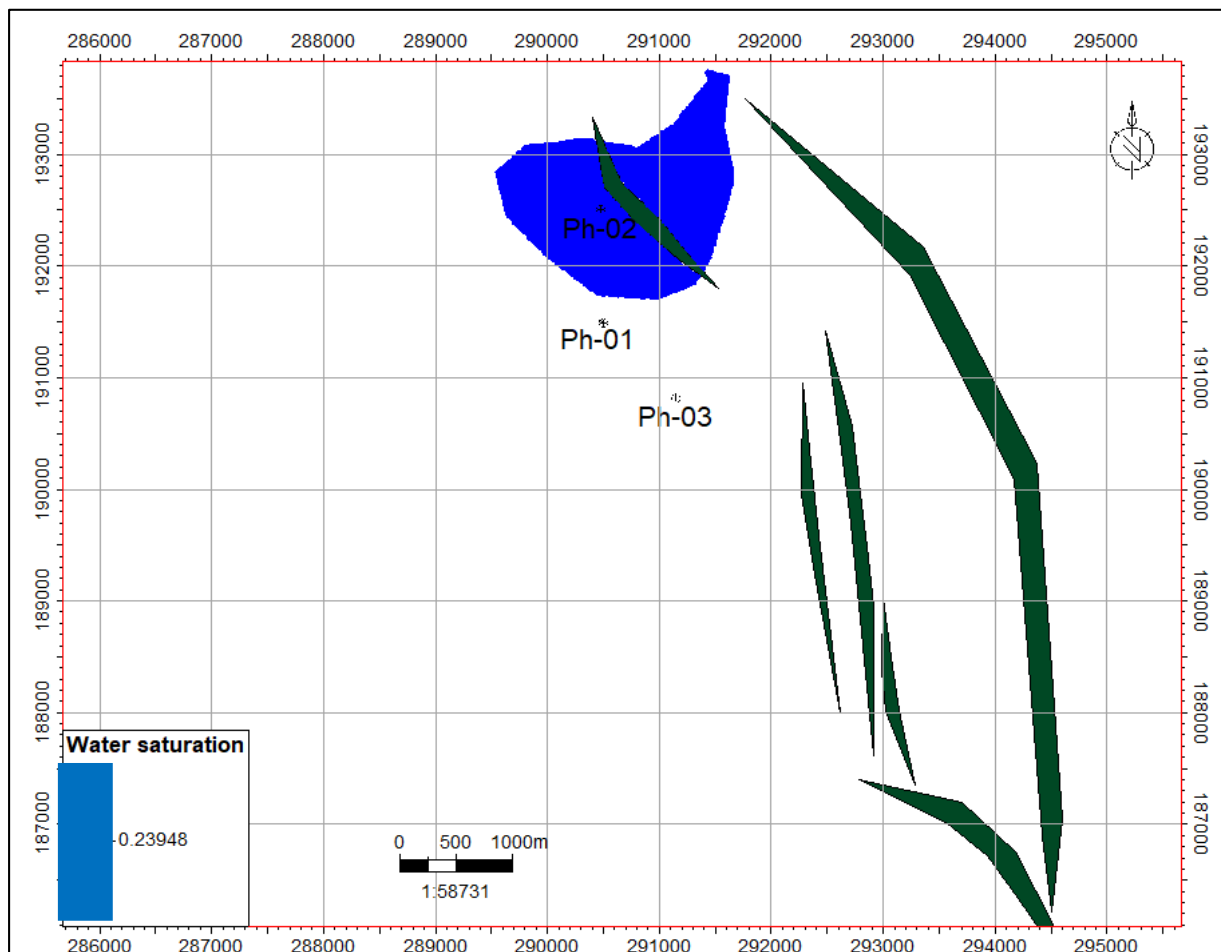


Fig. 19. Water Saturation Map for D10/Ph-02 Reservoir

4.25. Volumetric Estimation Of D-10/Ph-02

The volume estimation for the “D10/PH-02” reservoir, as derived from the updated property maps, reflects significant revisions based on recent geological and petrophysical interpretations. As illustrated in Figure 20, the net pay map indicates an oil column of **63 ft**, which notably exceeds the **30 ft** previously recorded in the Field Development Plan (FDP). This discrepancy underscores the impact of refined mapping and data integration.

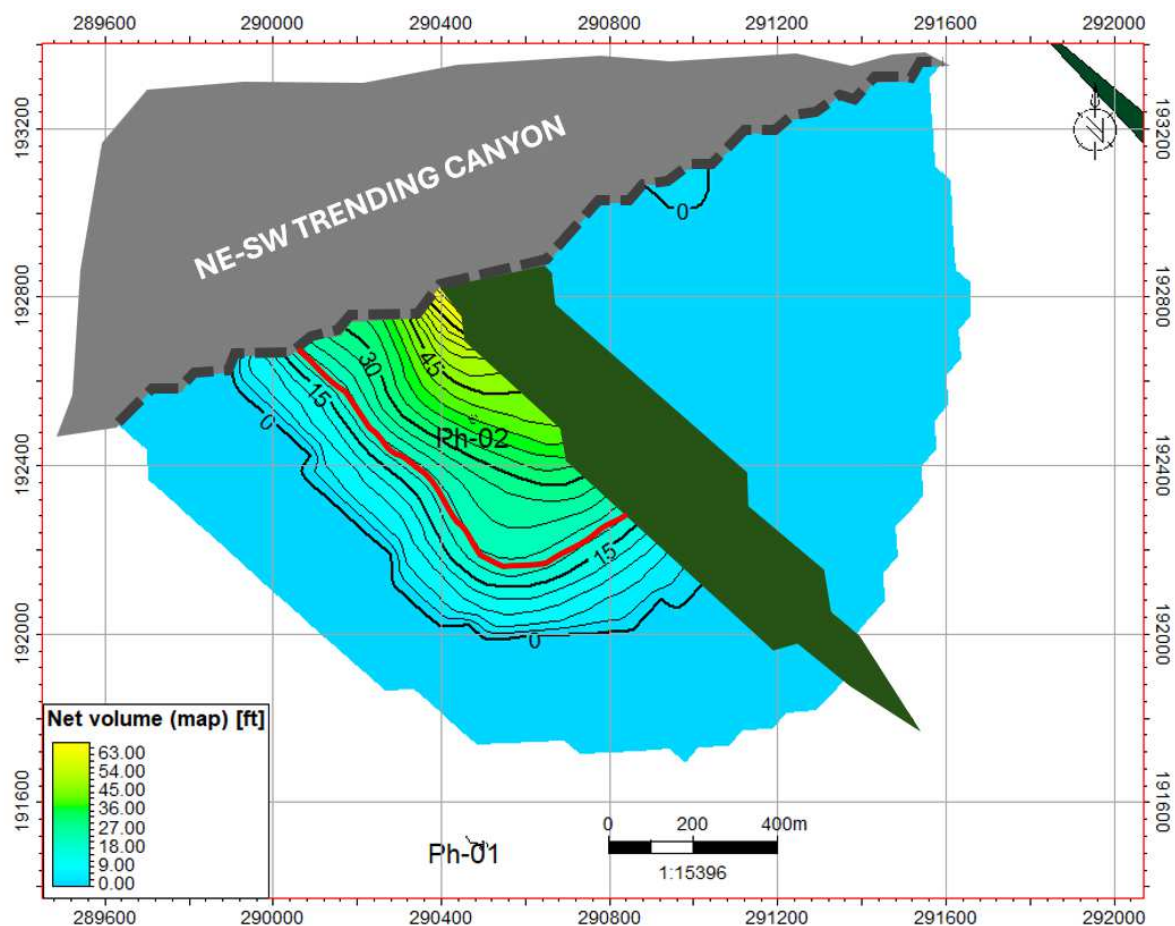


Fig. 20. D-10/PH-02 Reservoir Remaining Oil pay Map

Following the new interpretation, detailed in Table 2, the Stock Tank Oil Initially in Place (STOIIP) is now estimated at **3.98 MMSTBO**. This marks a downward revision from the **2P booked volume of 5.0 MMBO**, suggesting a more conservative and data-driven assessment of reservoir potential.

The contributing factors to this reduction are visually summarized in the waterfall chart presented in Figure 21. The variation in 2P STOIIP is primarily attributed to a decrease in mapped area, stemming from the latest seismic re-interpretation of the D10/PH-02 structure. Additionally, changes in reservoir properties particularly porosity and saturation are the result of a comprehensive petrophysical re-evaluation, further refining the volumetric outlook.

Table 2 Summation of computed volumes for D10/PH-02 Reservoir

HC Area (in oil) [acre]	Bulk volume [acre. ft]	Net volume [acre. ft]	Pore volume [acre. ft]	HCPV oil [acre.ft]	STOIIP [*10 ⁶ STB]
225.49	9536	9282	2838	2160	13.0998
118.29	2867	2819	862	656	3.98

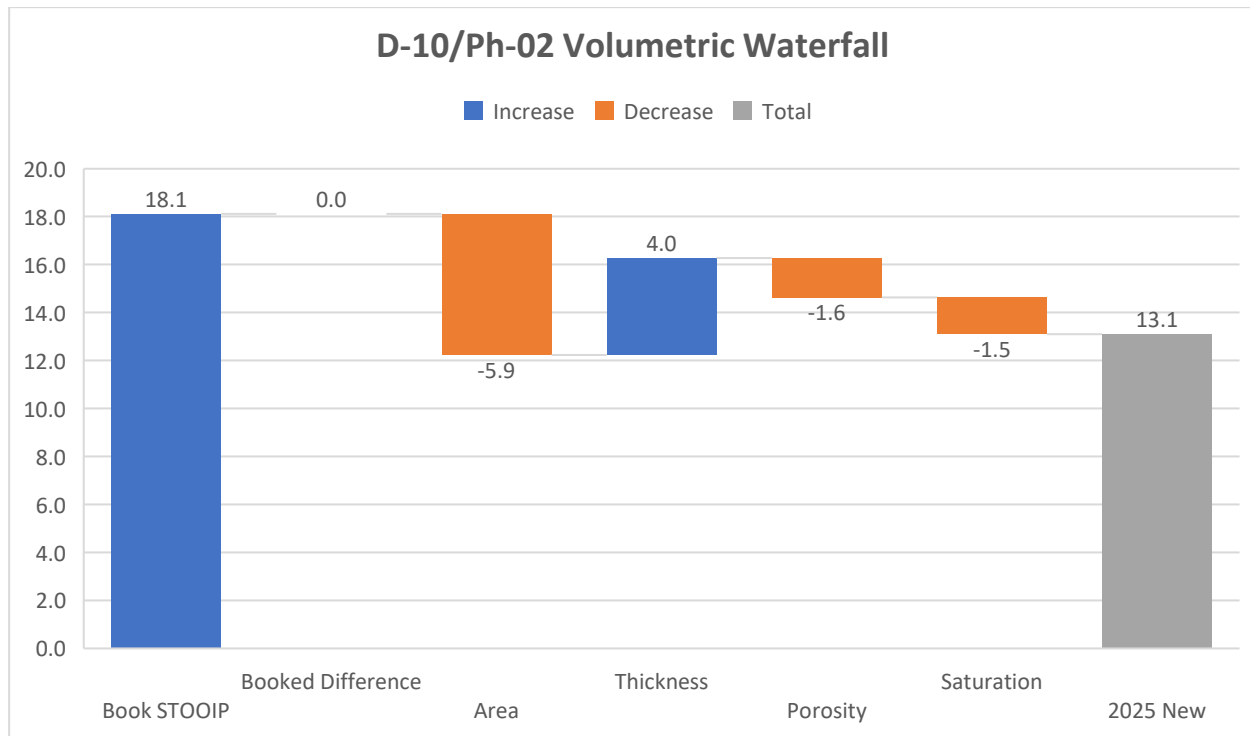


Fig. 21. Waterfall chart for 2P STOIP variation in booked vs. 2025 revalidation

3.3 Revised Fluid Contacts

As shown in figure 22, a comparative analysis between the previously interpreted oil-water contact (OWC) and the updated interpretation based on recent petrophysical evaluations reveals a shallower contact at -4950 ft TVDSS, in contrast to the original depth of -4964 ft. This reassessment, grounded in integrated well log correlations and production history, has led to several key updates:

- STOIP Reduction: Revised downward from 18.13 MMSTBO to 13.10 MMSTBO
- Recovery Factor Increase: Improved from 28.8% to 45.4%
- Net Developable Oil Pay: Increased from 75 ft to 90 ft

3.3.1 Implications of the Revised Oil-Water Contact (OWC) from -4964 ft to -4950 ft

1. Reduced Net Oil Column

- The effective oil column height has decreased from 75 ft to approximately 61 ft, directly influencing volumetric calculations and STOIP estimates.

2. Updated STOIP Estimates

- The revised OWC and associated reduction in reservoir area have resulted in a lower STOIP, now estimated at 13.10 MMSTBO, down from 18.13 MMSTBO.

3. Improved Recovery Factor

4. Development Strategy Adjustments

- The shallower OWC necessitates a reassessment of well placement to mitigate risks of early water breakthrough.
- Water shut-off techniques and completion interval designs may require optimization to align with the new fluid contact profile.

- Production forecasts and economic models should be recalibrated to reflect the updated reservoir dynamics.

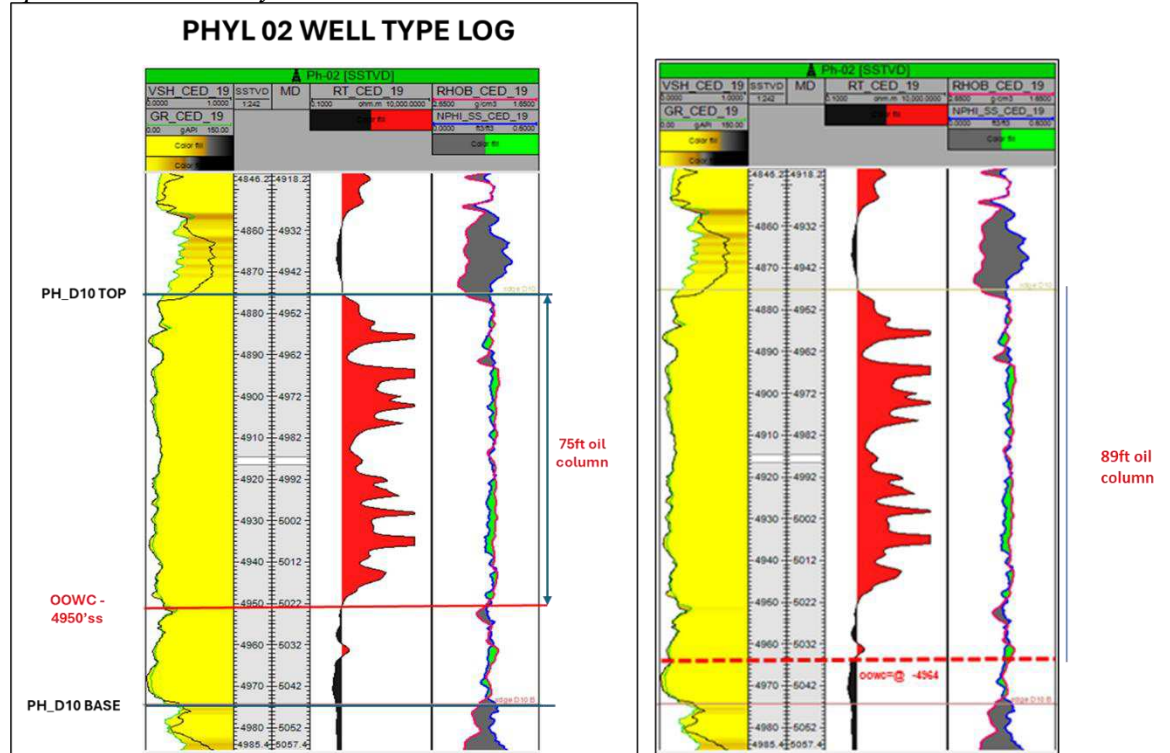


Fig. 22. Type Logs of PH-02 well comparing the two interpreted Oil Water Contacts in the D10/PH-02 Reservoir

4.3.2 Integrated Parameter Comparison and OWC Analysis

A comparison of the reservoir parameters between the INPUT FDP and New scenarios, including the revised Oil Water Contact (OWC) analysis is presented in table 3.

Table 3: Integrated Parameter Comparison

Parameter	INPUT FDP	New
Area [acre]	334	225
Gross Thickness [ft]	30.95	42.3
Net Thickness [ft]	30.9	41.2
NTG	0.97	0.97
Porosity	0.340	0.306
Sw	0.150	0.239
Volume [acre. ft]	18.11	13.10
OWC	-4964 ft TVDSS	-4950 ft TVDSS

3.4 Production History and Reservoir Dynamics

The PH-02D well stands as the sole active completion within the reservoir, having delivered a cumulative production of approximately **4.86 million stock tank barrels of oil (MMSTBO)** between 1994 and 2020. Over its operational lifespan, the well encountered several production challenges that impacted efficiency and recovery:

- **Sand production**, reaching rates of up to 100 lb/Mbbl, posed significant operational and equipment integrity concerns.
- **Water breakthrough** led to a notable increase in the basic sediment and water (BS&W) content, rising to 19.5%, which signalled encroachment and reduced oil cut.
- **Reservoir pressure depletion** was observed, with a 10.3% decline over an 11-year period, indicating progressive energy loss and the need for pressure support mechanisms.

5. Conclusions

This study underscores the critical importance of integrating seismic interpretation, petrophysical analysis, biostratigraphic data, and production history to unravel the complex subsurface architecture of the Phyl Field. By correlating these datasets, a more accurate reservoir characterization was achieved, previously overlooked hydrocarbon-bearing zones were identified, and proposed targeted redevelopment strategies to enhance field productivity.

The multidisciplinary approach not only resolved ambiguities in reservoir continuity and compartmentalization but also provided a robust framework for future field development planning. The success of this integrated workflow demonstrates its applicability to other mature fields within the Niger Delta Basin and similar geological settings worldwide.

By demonstrating the effectiveness of combining seismic, petrophysical, biostratigraphic, and production data, this work provides a replicable blueprint for maximizing hydrocarbon recovery and extending the productive life of mature fields. The insights gained from the Phyl Field study offer strategic guidance for future offshore developments across the Niger Delta Basin and reinforce the value of integrated subsurface analysis in driving informed, high-impact field redevelopment.

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