RESEARCH ARTICLE

Integrated Seismic Interpretation and Petrophysical Evaluation for Hydrocarbon Volumetric Estimation in the BUKS Offshore Field, Niger Delta, Nigeria

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Abstract

Hydrocarbon reserve estimation and reservoir characterization remain critical aspects of field development planning, particularly in mature offshore basins such as the Niger Delta. This study integrates 3D seismic interpretation with petrophysical analysis to evaluate reservoir quality and estimate hydrocarbon volumes within the BUKS offshore field, Niger Delta, Nigeria. Structural interpretation of the seismic data identified a NNW-trending rollover anticline associated with four major listric growth faults (F1–F4), forming the principal trapping system in the field. Petrophysical evaluation of four wells revealed favourable reservoir properties, with average porosity values ranging from 25% to 31%, permeability between 83 and 1452 mD, and shale volume varying from 20.5% to 38.6%. Water saturation values range from 15% to 41%, corresponding to hydrocarbon saturation values of 59%–85%, indicating good hydrocarbon potential across the mapped reservoirs. Volumetric calculations based on the interpreted reservoir parameters yielded a combined Stock Tank Oil Initially in Place (STOIIP) estimate of approximately 45.37 MMSTB, while a conservative recovery factor of 10% suggests recoverable reserves of about 4.54 MMSTB. The results indicate that the BUKS field possesses good reservoir quality, and the recoverable volume, while modest, may warrant further appraisal to assess development options, including potential tie-back to existing regional infrastructure. The study further demonstrates that integrating seismic interpretation with conventional petrophysical evaluation provides a practical and reliable approach for preliminary reserve estimation and field appraisal in offshore Niger Delta reservoirs.

Keywords: Niger Delta, BUKS field, seismic interpretation, petrophysical evaluation, empirical volumetric method, oil in place.

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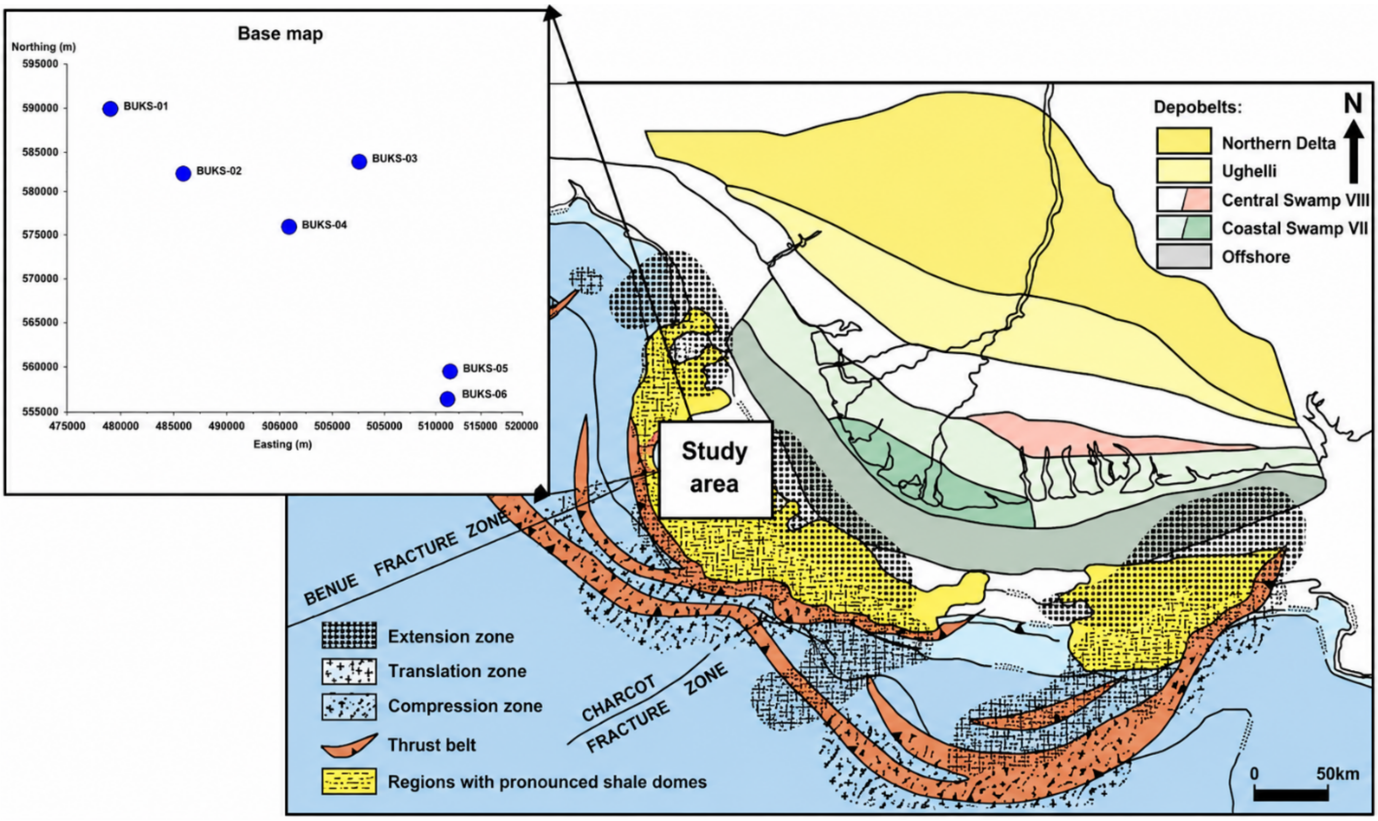

Figure 1. Base map of the BUKS offshore field within the Niger Delta Basin showing seismic coverage and well locations (four wells: BUKS-01, BUKS-02, BUKS-03, BUKS-04).

1 Introduction

Hydrocarbon exploration and production in mature basins such as the Niger Delta have become increasingly complex and expensive, as remaining prospects are frequently confined within structurally intricate deep-water fold-and-thrust belts and growth-fault systems that demand detailed seismic-based structural analysis [1, 2]. Most undrilled prospects are either deep offshore or structurally subtle, requiring accurate reservoir characterization to reduce drilling risk. A well-understood reservoir, delineated through integrated seismic and petrophysical evaluation, ultimately leads to better field management, optimal well placement, and realistic reserve reporting [3, 4]. Therefore, reliable estimation of petrophysical parameters and hydrocarbon volumes is critical for successful field development.

Detailed three-dimensional reservoir simulation modeling, incorporating sand-body architecture, heterogeneity treatment, and geostatistical constraints, is widely regarded as the most accurate approach for reserve calculation [5, 6]. However, such models are time-consuming and require extensive data. Empirical formula techniques offer a rapid, complementary approach that provides a preliminary constraint and a remedial cross-check before detailed geostatistical work [7, 8]. This flexibility is particularly valuable for early-stage field appraisal, where quick but robust volumetric estimates are needed to prioritize drilling.

This study integrates 3D seismic interpretation with petrophysical evaluation of four wells in the BUKS offshore field, Niger Delta, to: (i) map structural traps and fault geometry; (ii) determine reservoir porosity, water saturation, net pay, and hydrocarbon saturation; and (iii) estimate hydrocarbon volumes using empirical volumetric equations. The novelty lies in the combined use of seismic structural mapping and empirical petrophysics to provide a rapid, cost-effective volumetric assessment prior to full-field geostatistical modeling.

2 Geological Setting

The Niger Delta is one of the world's largest hydrocarbon provinces, located in the Gulf of Guinea, southern Nigeria, between longitudes 4°–9°E and latitudes 4°–9°N (Figure 1). The delta is a classic passive-margin clastic wedge that reaches a maximum thickness of about 12 km [9, 10]. It consists of three diachronous formations: the basal Akata Formation

(Paleocene–Pliocene), predominantly marine shales that serve as the principal source rock; the overlying Agbada Formation (Eocene–Quaternary), an alternating sequence of sandstones and shales that constitutes the main reservoir interval; and the Benin Formation (Oligocene–Recent), dominantly continental sandstones [11–13].

The structural evolution of the Niger Delta is controlled by gravity tectonics, shale mobility, and listric growth faulting [14, 15]. The BUKS offshore field (Figure 1) is located within the western part of the Niger Delta offshore depobelt. It covers approximately 720 km^2 and exhibits NW–SE trending growth faults with associated rollover anticlines, which are the primary trapping mechanisms.

3 Materials and Methods

3.1 Dataset

The study used a 3D seismic volume (post-stack time migrated) covering the BUKS field, acquired in 2015 with a bin size of 12.5 m × 12.5 m, a record length of 5 s, and a dominant frequency of 35 Hz. Four wells (BUKS-01 to BUKS-04) were available, each with a full suite of logs: gamma ray (GR), resistivity (deep, medium, shallow), neutron porosity (NPHI), bulk density (RHOB), and sonic (DT). Checkshot data were provided for time-depth conversion. All data were imported into Schlumberger Petrel (version 2017) for interpretation.

3.2 Seismic Interpretation

Seismic interpretation followed a standard workflow: (1) well-to-seismic tie using checkshots and synthetic seismograms; (2) fault interpretation on inline and crossline sections; (3) horizon picking of two reservoir tops (H1 and H2) based on reflector continuity and well markers; (4) time-structure mapping; and (5) depth conversion using interval velocities derived from checkshots. Faults were interpreted as listric growth faults and antithetic faults. The interpreted horizons and faults were gridded to produce time and depth structure maps.

3.3 Petrophysical Evaluation

Petrophysical parameters were calculated using standard empirical equations [7]. Reservoir sands were identified using gamma-ray (< 75 API) and resistivity (> 10 ohm·m) cutoffs, and confirmed by neutron–density crossover indicating hydrocarbon effect. The following equations were applied.

Gamma-ray index [16]:

$$I_{GR} = \frac{GR_{\text{log}} - GR_{\text{min}}}{GR_{\text{max}} - GR_{\text{min}}} \tag{1}$$

where GR_{log} is the measured gamma-ray, and GR_{min} and GR_{max} are clean sand and shale reference values, respectively.

Shale volume [17] (for Tertiary clastics):

$$V_{\text{sh}} = 0.083(2^{3.7 I_{GR}} - 1) \tag{2}$$

Density porosity [18]:

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \tag{3}$$

where $\rho_{ma} = 2.65$ (matrix density, quartz), $\rho_f = 1.00$ (fluid density), and ρ_b is bulk density from logs.

Formation factor (Humble equation; [19]):

$$F = 0.62\phi^{-2.15} \tag{4}$$

Water saturation [20]:

$$S_w^n = \frac{F R_w}{R_t} \tag{5}$$

using $n = 2.0$, $R_w = 0.025$ (from nearby field data), and R_t the deep resistivity. Solve for S_w as $S_w = (F R_w / R_t)^{1/n}$.

Hydrocarbon saturation:

$$S_h = 1 - S_w \tag{6}$$

Irreducible water saturation [21]:

$$S_{w,\text{irr}} = \sqrt{\frac{2000}{F}} \tag{7}$$

(or equivalently $S_{w,\text{irr}} = (2000/F)^{0.5}$).

Permeability [22]:

$$K = \left(\frac{250\,\phi^3}{S_{w,\text{irr}}}\right)^2 \tag{8}$$

(note units: millidarcies).

Bulk volume of water (BVW):

$$BVW = \phi \cdot S_w \tag{9}$$

Hydrocarbon pore volume (HCPV):

$$HCPV = \phi \cdot (1 - S_w) \tag{10}$$

Net-to-gross ratio (N/G):

$$N/G = \frac{\text{Net thickness}}{\text{Gross thickness}} \tag{11}$$

Net thickness is defined here as pay intervals with $\phi \geq 0.10$ and $V_{sh} \leq 0.50$.

3.4 Volumetric estimation

Original oil in place (OOIP) was estimated using the standard volumetric equation commonly applied in petroleum reservoir engineering [23].

$$OOIP = 7758 \cdot A \cdot h \cdot \phi \cdot \frac{1 - S_w}{B_o} \tag{12}$$

where A = area from depth structure map (acres), h = net pay thickness (ft), ϕ = average effective porosity (fraction), S_w = average water saturation (fraction), B_o = oil formation volume factor (reservoir bbl/STB), here $B_o = 1.3$ reservoir bbl/STB, adopted from typical PVT ranges (1.2–1.4 reservoir bbl/STB) reported for analogous Niger Delta offshore oils of comparable API gravity, in the absence of direct PVT sampling for the BUKS field. The factor 7758 converts acre-ft to reservoir barrels; dividing by Bo then yields stock tank barrels (STB).

Table 1. Probabilistic range of STOIIP based on first-order propagation of the stated uncertainties in area ($\pm 5\%$), net pay ($\pm 15\%$), and B_o (1.2–1.4 reservoir bbl/STB), combined by root-sum-square. P50 corresponds to the base-case values in Table 4.

Case	Sand A	Sand B	Total
P90 (low)	7.04	30.34	37.38
P50 (base)	8.55	36.82	45.37
P10 (high)	10.06	43.30	53.36

Values in MMSTB. Combined relative uncertainty $\approx \pm 17.6\%$.

Stock-tank oil initially in place (STOIIP): Because Eq. (12) already divides by the oil formation volume factor B_o, the resulting volume is expressed directly in stock-tank barrels (STB). The term OOIP as used in this study is therefore numerically equivalent to STOIIP, and no additional unit conversion is applied.

Primary recoverable reserves: estimated using recovery factor $RF = 0.10$ (10%), appropriate as a conservative estimate for a fault-dominated, potentially compartmentalized reservoir:

$$\text{Recoverable oil} = OOIP \times RF \tag{13}$$

3.5 Uncertainty and Assumptions

Key uncertainties include: (i) Archie parameters (m, n, a) assumed typical for clean sand; (ii) R_w derived from nearby fields, not measured; (iii) seismic depth conversion uncertainty estimated at $\pm 5\%$; (iv) net pay cutoff sensitivity ($\pm 15\%$ in net thickness). No well-test or production data were available to calibrate the recovery factor.

4 Results and Discussion

4.1 Structural Interpretation

Well-to-seismic tie (Figure 2) showed good correlation between synthetic seismograms and seismic reflections at the two reservoir levels (H1 and H2). Four major listric faults (F1, F2, F3, F4) were interpreted (Figure 3). Faults F1 and F3 are the main basinward-dipping growth faults (south-dipping), while F2 and F4 are antithetic faults dipping north. All faults strike NW-SE, consistent with regional Niger Delta extensional tectonics [9]. The faults bound a rollover anticline that constitutes the main structural trap.

Time structure maps (Figures 4 and 5) and depth structure maps (Figures 6 and 7) for horizons H1 and H2 reveal a NNW-trending anticlinal closure with three-way dip closure against faults F2 and F3. The structural high is located in the northwestern part of the field. Closure areas are approximately 240 acres for H1 and 830 acres for H2. The depth maps show that the reservoir is shallower on the crest (~3200 m) and deepens to the south and east (~3600 m). The fault throws range from 30 to 80 ms (~50–140 m).

Table 1 presents an approximate P10/P50/P90 range obtained by first-order combination of the uncertainties already identified in Section 3.5, providing a probabilistic context for the deterministic P50 estimate reported above. This simplified approach does not capture uncertainty in porosity, water saturation, or structural closure area independently, and should be superseded by a full Monte Carlo or geostatistical uncertainty analysis in future work.

4.2 Petrophysical Evaluation

Four reservoir sand intervals (two in each of two stacked reservoirs, Sand A and Sand B) were identified from well logs. Figure 8 (well correlation panel) shows the correlation of these sands across the four wells.

Petrophysical results are summarized in Tables 2 and 3.

Interpretation: Porosity ranges from 25–31%, indicating excellent reservoir quality. Permeability is

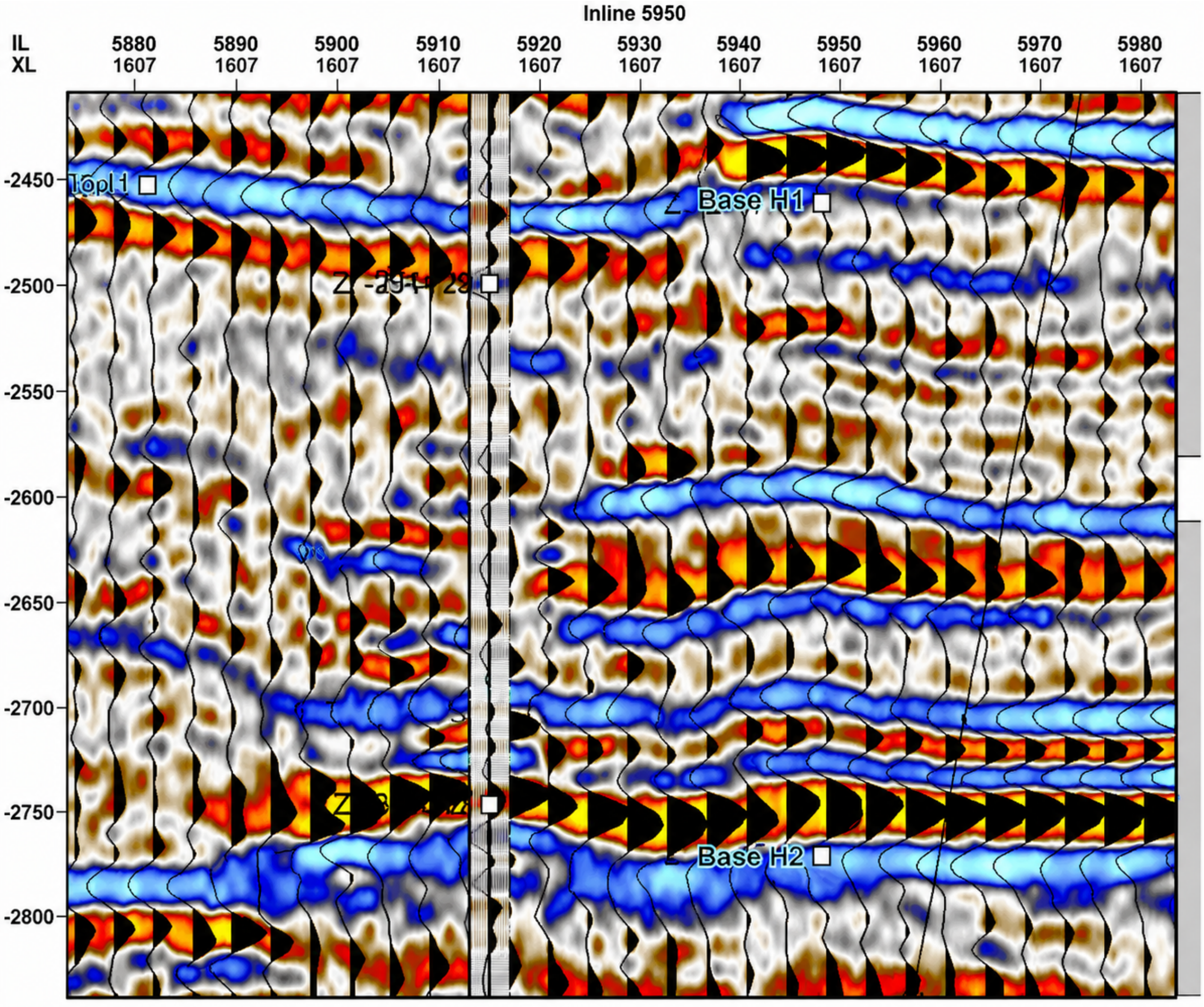

Figure 2. Crossline 1607 through well BUKS-02 showing well-to-seismic tie. Red circles mark picked horizons H1 and H2.

Table 2. Petrophysical data for Sand A reservoir.

Well	Gross (m)	Vsh (%)	Porosity (%)	Eff. Porosity (%)	Swirr (%)	Perm (mD)	Net/Gross (%)	Sw (%)	Sh (%)
BUKS-01	18	20.5	31	25	32.7	142.6*	63	25	75
BUKS-02	20	22	30	23	13.0	1079†	79	18	82
BUKS-03	12	22.1	30.7	24	20.0	298.6*	81	33	67
BUKS-04	11	28.7	29.3	21	12.0	106†	72	41	59

*Computed using Eq. (8) with ϕ_{eff} expressed as a fraction (not percentage); †Does not reproduce Eq. (8) and is pending re-verification against original log data.

moderate to very high (83–1452 mD). It should be noted that permeability does not enter the STOIIP calculation (Eq. 12) and therefore does not affect the volumetric results in Section 4.3; however, since six of the eight tabulated permeability values do not reproduce Eq. (8) using the tabulated ϕ_{eff} and $S_{w,\text{irr}}$ (see footnotes to Tables 2 and 3), the qualitative characterization of reservoir quality as "excellent" to "very high permeability" should be regarded as provisional pending re-verification

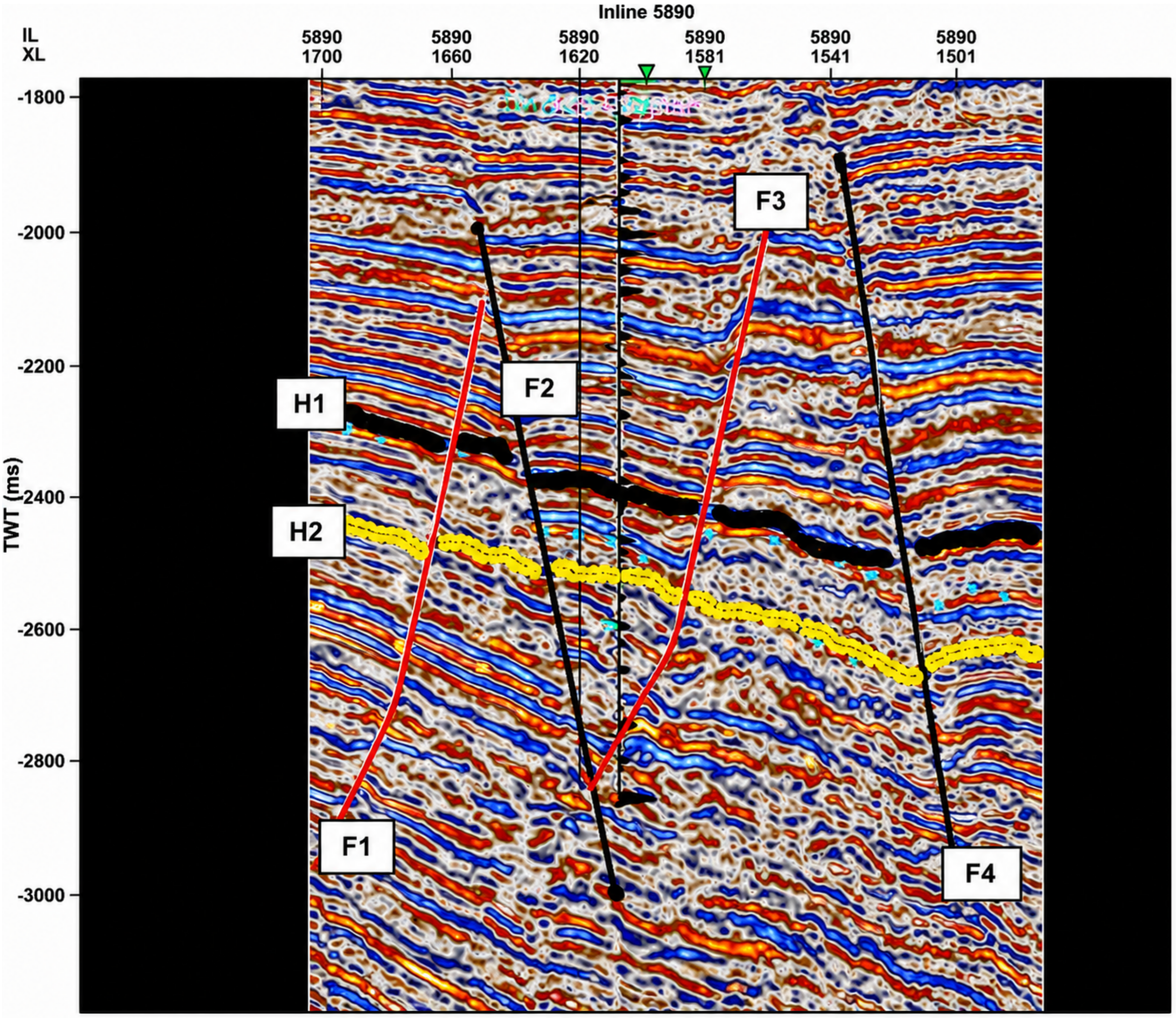

Figure 3. Inline 5890 showing fault geometry and picked horizons (H1, H2). Faults are annotated F1–F4.

Table 3. Petrophysical data for Sand B reservoir.

Well	Gross (m)	Vsh (%)	Porosity (%)	Eff. Porosity (%)	Swirr (%)	Perm (mD)	Net/Gross (%)	Sw (%)	Sh (%)
BUKS-01	24	28.3	29	20	34.5	83†	84	20	80
BUKS-02	26	35.1	27.8	18	10.5	1452†	75	15	85
BUKS-03	24	38.6	26.9	17	14.0	93†	77	23	77
BUKS-04	8	38.0	25.0	16	10.7	122†	61	18	82

†Does not reproduce Eq. (8) using the tabulated ϕ_{eff} and $S_{w,\mathrm{irr}}$; pending re-verification against original log data.

against the original log data. Shale volume (20–39%) is moderate and does not severely impair porosity. Water saturation varies from 15–41%, corresponding to hydrocarbon saturation of 59–85%, which is favourable for commercial accumulation. The reservoir sands show a coarsening-upward (funnel) pattern on gamma ray logs, suggesting a high-energy progradational environment [15]. Preliminary bulk volume water (BVW = $\phi \times S_w$, Eq. 9) computed from the tabulated porosity and saturation values also varies noticeably across wells and between Sand A and Sand B, consistent with the reservoir heterogeneity inferred from the porosity and permeability trends discussed above; a detailed BVW distribution map is left for future work. Across most wells, Sw exceeds Swirr, indicating that the reservoir would produce

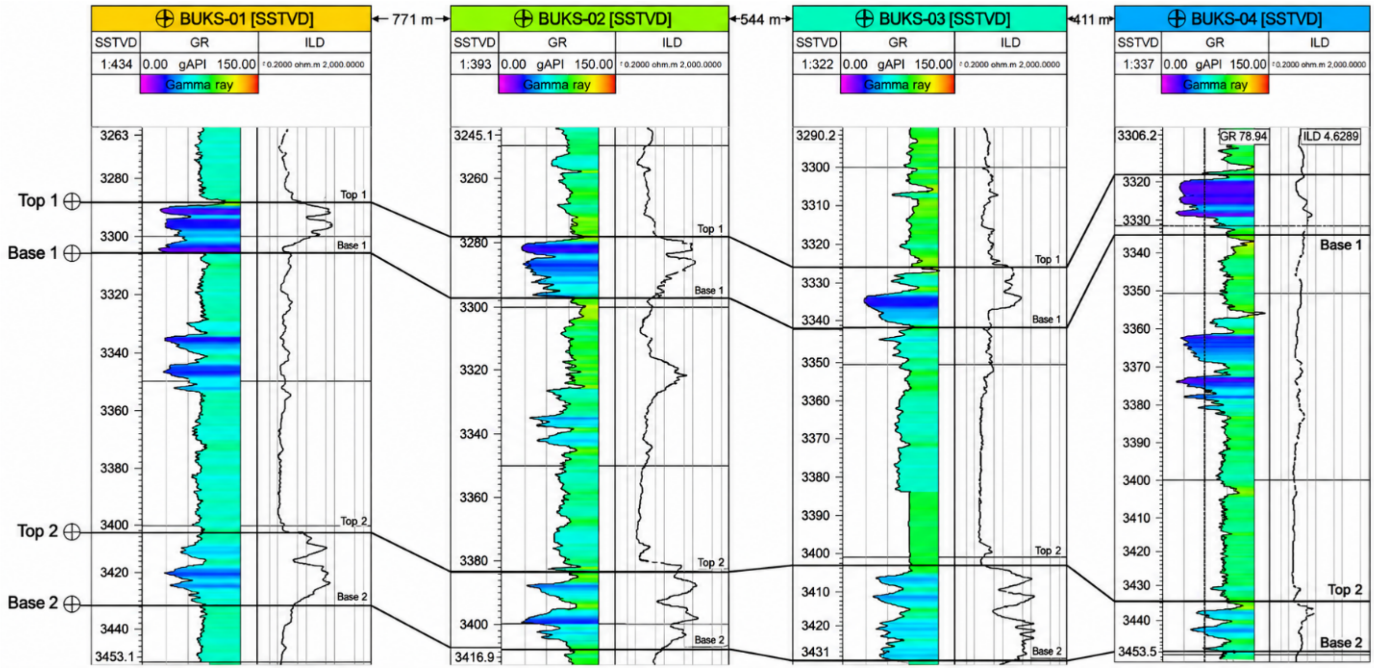

Figure 4. Time structure map of horizon H1 showing fault polygons and anticlinal closure.

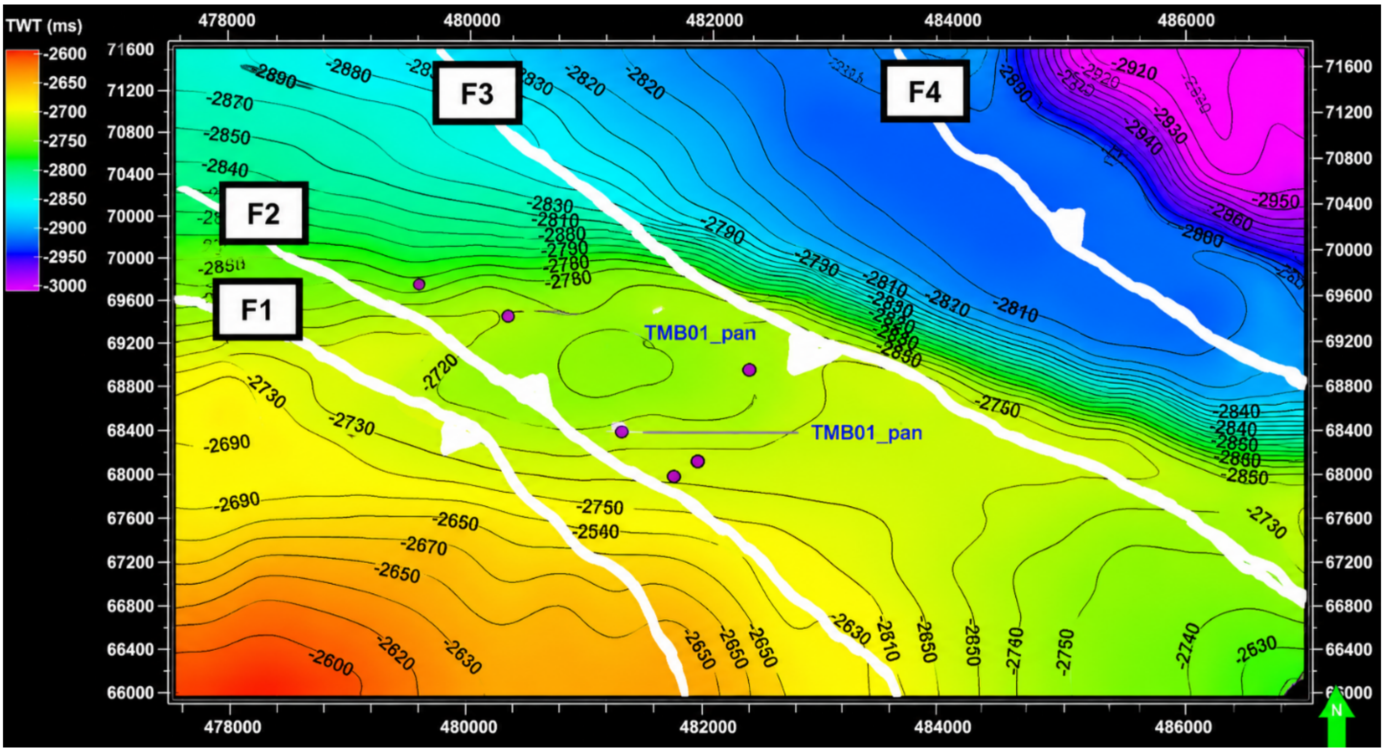

Figure 5. Time structure map of horizon H2.

some water but not excessively. However, well BUKS-01 shows Sw values (25% in Sand A, 20% in Sand B) below the corresponding Swirr (32.7% and 34.5%), which is not physically consistent since Swirr represents the lower bound of water saturation. This discrepancy is most likely attributable to errors in the resistivity (Rt) or porosity inputs used for BUKS-01 and requires re-verification against the original log data before being incorporated into the volumetric model.

4.3 Volumetric Estimation

Using the empirical volumetric equation (Section 3.4) and the average petrophysical parameters from Tables 2 and 3, the OOIP and STOIIP were calculated. The results are shown in Table 4.

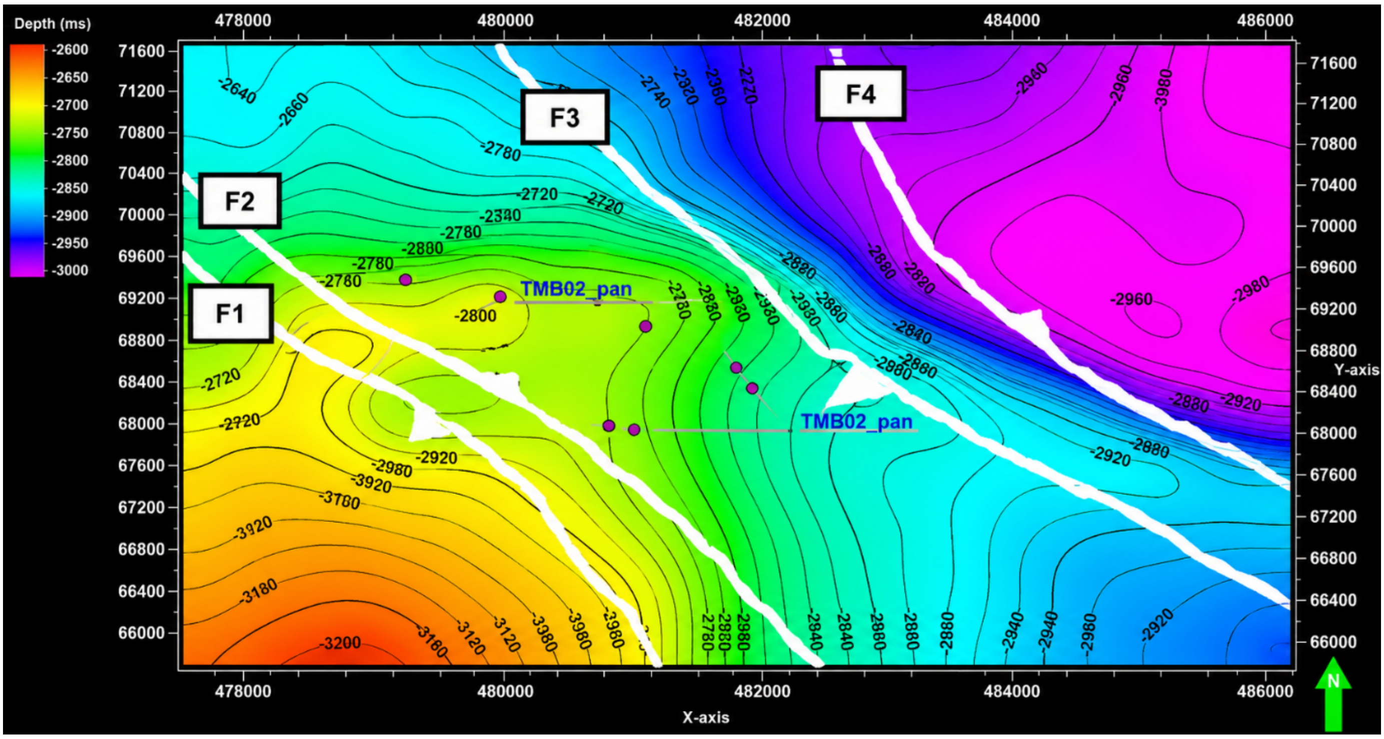

Figure 6. Depth structure map of horizon H1 (converted using checkshot velocities). Contour interval 20 m.

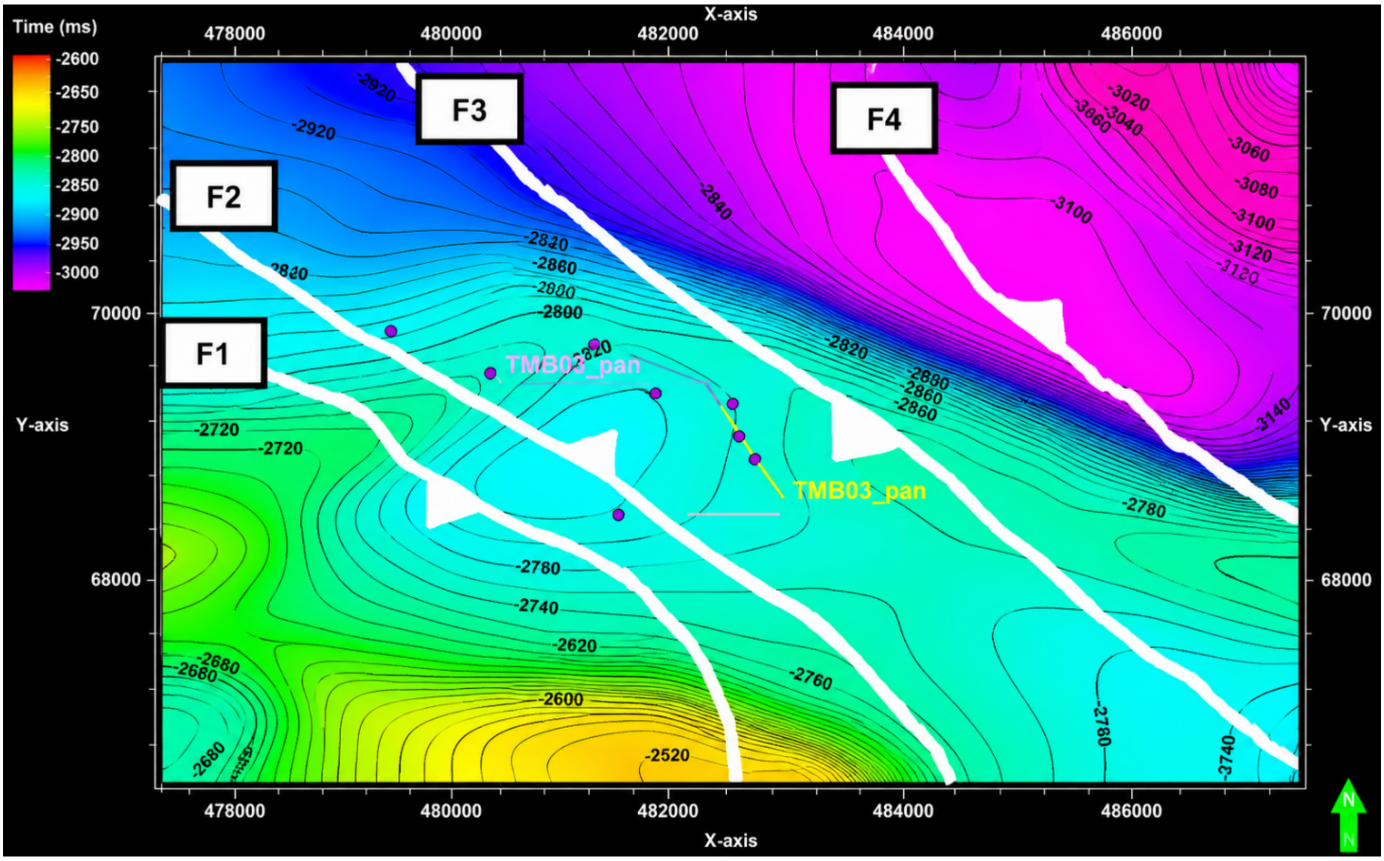

Figure 7. Depth structure map of horizon H2.

Note: The large difference between Sand A and Sand B is due to the much larger areal extent of Sand B. The combined STOIIP of 45.37 MMSTB is a significant volume. However, the high value for Sand B should be treated with caution because it is based on extrapolation of average net pay over a

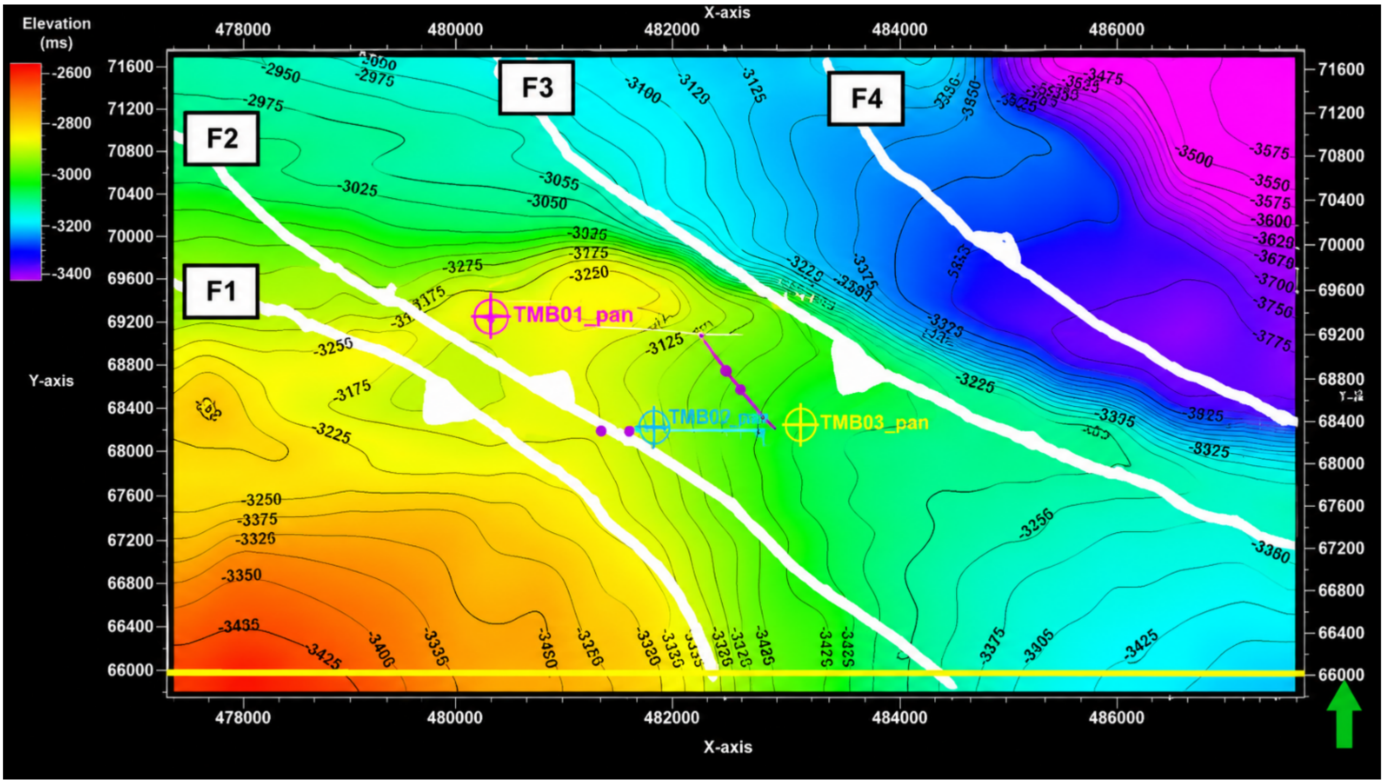

Figure 8. Well correlation panel of BUKS field showing delineated reservoir sand units Top1/Base1 (Sand A) and Top2/Base2 (Sand B). Depth scale in meters.

Table 4. Volumetric data for Sand A and Sand B reservoirs (recalculated using effective porosity and net pay derived from Gross × Net/Gross in Tables 2 and 3).

Parameter	Sand A	Sand B
Area (acres)	237.22	830.30
Net pay (ft)	36.73	51.68
Average effective porosity (fraction)	0.23	0.18
Water saturation (fraction)	0.29	0.19
Hydrocarbon saturation (fraction)	0.71	0.81
Oil formation volume factor (bbl/STB)	1.3	1.3
OOIP / STOIIP (MMSTB)	8.55	36.82
Total STOIIP (both sands): 45.37 MMSTB		
Primary recovery factor (assumed): 10%		
Primary recoverable reserve: 4.54 MMSTB		

large area without well control in the central part of the closure. In addition, the Sand A average water saturation (29.25%) incorporates the anomalous BUKS-01 value (Sw = 25%), which lies below its own computed Swirr (32.7%) and has not yet been re-verified against the original log data (see Section 4.2). Excluding BUKS-01 raises the Sand A average Sw to approximately 30.7% (BUKS-02 to BUKS-04 only), which would reduce the Sand A STOIIP by roughly 2%. The effect on the combined field STOIIP is therefore small, but the BUKS-01 value should be re-verified before this volumetric estimate is used for formal reserves booking.

The empirical volumetric estimate gives a preliminary STOIIP of 45.37 MMSTB. This is a reasonable figure for an offshore Niger Delta field of this size. The primary recoverable reserve of 4.54 MMSTB (10% recovery factor) is conservative; with better reservoir connectivity and aquifer support, recovery could be higher (15–25%). Nevertheless, the volumetric results confirm that the BUKS field contains a technically producible hydrocarbon accumulation; whether it is independently commercially viable, or more economically developed as a tie-back to nearby existing offshore infrastructure, requires further economic evaluation beyond the scope of this study.

5 Conclusions

Integration of 3D seismic interpretation and petrophysical evaluation of four wells in the BUKS offshore field, Niger Delta, has successfully delineated the structural framework and reservoir properties, enabling empirical volumetric estimation of hydrocarbon in place. The structural interpretation reveals a NNW-trending rollover anticline bounded by four NW-SE listric faults (F1–F4), forming a three-way dip closure that is the primary trapping mechanism. Petrophysical analysis shows excellent reservoir quality with average porosity of 25–31%, permeability of 83–1452 mD, and hydrocarbon saturation of

59–85%. The estimated Stock Tank Oil Initially in Place (STOIIP) is 45.4 MMSTB, with a primary recoverable reserve of approximately 4.5 MMSTB at the 10% recovery factor. The empirical formula method provides a rapid, cost-effective preliminary volumetric assessment that can serve as a constraint for future 3D geostatistical modeling and field development planning. The BUKS field is confirmed to have good reservoir potential, and the estimated recoverable volume of approximately 4.5 MMSTB indicates that formal commercial viability should be evaluated in the context of specific development scenarios, such as tie-back to existing regional infrastructure, rather than assumed as a standalone development.

6 Recommendations for Reservoir Management

The recovery factor of 10% assumed in this study is conservative and likely reflects a weak natural drive mechanism (limited aquifer or solution gas drive). Given the modest recoverable volume estimated for the BUKS field (approximately 4.5 MMSTB), the most cost-effective near-term path to improving recovery is water flooding, which could raise the recovery factor to 35–45% if reservoir connectivity and injectivity prove favorable; this would still require careful economic justification given the field's size. More capital-intensive enhanced oil recovery methods, such as thermal (steam injection) or chemical flooding, are unlikely to be economically justified at this reserve scale in an offshore setting and are not recommended unless subsequent appraisal substantially increases the reserve estimate or the field is developed jointly with adjacent accumulations. Prior to any injection program, a detailed reservoir simulation study is required to quantify compartmentalization and sweep efficiency. The primary near-term recommendation is to acquire pressure data and production logs from the first few wells to refine both the recovery factor estimate and the volumetric model described in Section 4.3.

Data Availability Statement

Data will be made available on request.

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Conflicts of Interest

The authors declare no conflicts of interest.

AI Use Statement

The authors declare that no generative AI was used in the preparation of this manuscript.

Ethical Approval and Consent to Participate

Not applicable.

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