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Integration of Seismic Data to Petrophysical Results for the Volumetric Appraisal of BOK Field, Onshore Niger Delta Basin

Okechukwu Frank Adizua[1,*], Kufre Israel Udo[2], Emem John James[1]

[1]Geophysics Research Group – GRG, Department of Physics, Faculty of Science, University of Port Harcourt, Nigeria
[2]Department of Physics, Faculty of Physical Sciences, University of Uyo, Nigeria

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Abstract BOK is a prospect field in the onshore part of the Niger Delta Basin with huge hydrocarbon potential but is yet to be fully economically evaluated by means of volumetric appraisals. This study therefore seeks to economically evaluate the BOK field in terms of its hydrocarbon volumetric potential (reserves) to assess its prospectivity. This work would provide valuable insights to the asset managers of the BOK field to guide their field development plans. Well log data from three wells and 3D seismic data from the BOK field were integrated to perform a thorough volumetric evaluation of the field in order to estimate its volumetric reserves and assess its economic viability. Leveraging on the petrophysical results from a previous investigation in the BOK field, the Petrel program was utilized for the comprehensive volumetric assessment. According to our findings, the BOK field was found to have anticlinal faulted structures that serve as the trapping mechanisms for hydrocarbon reservoirs. According to the structural interpretation, the well data also shows good correlations of the sand bodies throughout the entire seismic section and a correlation of the sand shale inter-beds. Four hydrocarbon-bearing reservoir sand formations were identified by petrophysical investigation. The shale volume ranged from 13.09% to 22.95%, the effective porosity ranged from 19.24% to 24.23%, the net to gross ranged from 38.66% to 75.40%, and the hydrocarbon saturation ranged from 54.85% to 72.53%. Volumetric estimation was carried out on two reservoirs with an estimated HCIP of 92MMbbl and 301MMbbl. By combining the findings from volumetric estimation, well log analysis, structural interpretation, and petrophysical properties, it became clear that both reservoirs had good to very good petrophysical properties. As a result, they were classified as prolific reservoir systems with commercial hydrocarbon fluid saturations based on the estimated hydrocarbon in place (HCIP) which should be used for commercial purposes. The BOK field from our findings has a prolific reservoir system that should be harnessed due to its vast reserves.

Keywords BOK Field, Integrating Seismic and Well Log Data, Volumetric Appraisal, Prospectivity Assessment, Prolific Reservoir Systems

1. Introduction

It is necessary to continuously characterize reservoirs for increased oil recovery in order to meet the growing global demand for petroleum. There is still a lot of oil in existing fields because recovery rates are modest, but it is unlikely that the number of fresh discoveries of massive conventional oil fields will be sufficient to supply these demands over time. Current oil fields will continue to provide the majority of future oil output. Information from the fields of geology, geophysics, and reservoir engineering will surely be integrated into the science of reservoir characterization. The process of estimating the reservoir volume using maps produced from the seismic and petrophysical data of the drill wells is known as volumetric appraisal or evaluation. In order to determine the amount of hydrocarbon and the likely related reserves, this method is used in the early stages of exploration [1]. Oil and gas reservoirs can be characterized using a range of geophysical methods and instruments. A crucial problem for the petroleum industry's economics is estimating the volume of hydrocarbons. Estimating reserves and assessing the effectiveness of recovery after significant production are crucial in production. They also serve as a foundation for more complex research, such as reservoir simulations. The study of the physical and chemical characteristics of rocks and the fluids they contain is known as petrophysics.

The oil and gas industry depends heavily on the definition of petrophysical characteristics such as permeability, fluid saturation, area extent, reservoir thickness, and porosity. The majority of the hydrocarbons generated in the Niger Delta come from deposits in the pores of permeable and porous rock formations. These "spaces" are determined by the rock's porosity, a crucial petrophysical characteristic. Fluid saturation, which measures the amount of gas, water, or oil in the rock's pore spaces, is crucial for figuring out how the fluids are distributed throughout the reservoir. The amount of hydrocarbon reserves contained in the reservoir is determined by the porosity and hydrocarbon saturation. When estimating the volume of hydrocarbons, thickness is another important petrophysical metric. To determine the thickness of the productive beds in particular reservoirs, the thickness of certain rock beds—like shale, which has virtually no recoverable oil because of its low permeability—must be computed and subtracted from the gross thickness. Hydrocarbon volume estimation also requires areal extent. It is derived from seismic data and is regarded as the reservoir's area. Seismic data offers both inter-well information and fine structure interpretation, making it a crucial approach for reservoir characterization and prediction [2]. All of these demonstrate how important it is to determine these petrophysical characteristics when assessing the volume of hydrocarbons. Numerous other characteristics, like the rock's mineralogy, pore size, and the type of fluid itself, affect these characteristics. Some of these characteristics may be consistent in a homogeneous reservoir, whereas they may differ greatly in a heterogeneous reservoir. Well logs and three-dimensional seismic data are integrated to describe the reservoir in reservoir development projects, where understanding the reservoir's thickness and extent is crucial.

The study's aim is to conduct a volumetric assessment and appraisal of the BOK field in the onshore Niger Delta Basin by integrating 3D seismic data with petrophysical parameters that were previously established by Adizua et al. [3]. Subtle information for describing reservoirs in the BOK field will be provided by the combination of 3D seismic data and petrophysical studies. This would therefore enable the asset managers to evaluate their assets for future field development plans by offering insightful information on the direct forecast of hydrocarbon reservoir features. This study's scope will include integrating seismic and well log data to analyze the BOK field's prospectivity. Both qualitative and quantitative interpretations will be applied to the well log. Seismic data will be used to map reservoir prospects identified from wells in order to pinpoint closures. Lastly, the economic viability of the identified reservoir will be ascertained by quantifying the hydrocarbon volume utilizing inputs from well logs and seismic data. Around the topic of this research, a few very similar studies have been conducted in the Niger Delta Basin. Hydrocarbon reserves in the Niger Delta Basin's Umoru Field were estimated by Isaac and Aigbedion [4] using seismic and borehole data. Ihianle et al. [5] performed structural interpretation in the Niger Delta Basin's "X-Y" field using well logs and 3D seismic data. Other studies on the theme include those by Mgbonta et al. [6], Egbe et al. [7], Emujakporue and Enyenihi [8], and Salami et al. [9]. The main intended deliverable of the current study is a comprehensive and nearly accurate economic appraisal of the BOK field, which is made possible by the integration of the 3D seismic dataset of the field in the presence of sufficient well controls around it. This provides a more comprehensive opportunity to perform better and more informed (detailed) volumetric computations and assessments, leveraging the structural maps that would be produced from the 3D seismic data.

2. Location of the BOK Field, Geological Characteristics and Settings

BOK field is located in the onshore Niger Delta Basin between longitude 6^0 34′ 52.2676’’E to 6^0 47′ 53.3275’’E and latitude 5^0 13′ 0.2201’’N to 5^0 19′3.7854’’N. Equatorial Guinea, Cameroon, and Nigeria are all part of the Niger Delta province. The province is located in West Africa's Gulf of Guinea and has a single petroleum system known as the Tertiary Niger Delta (Akata-Agbada) petroleum system in Nigeria. The Agbada Formation, which targets structural traps, is the primary source of oil and gas extraction in the region [10, 11]. As the South Atlantic started to open up beginning in the Late Jurassic and ending in the mid-Cretaceous, the Niger Delta Basin was created by a failed rift junction during the separation of the South American and African plates [12, 13]. The Niger River, which has the third-largest drainage area in Africa and the ninth-largest in the world, provides sediments to the Delta [14]. The overall area of the Niger Delta is 300,000 km^2, its sub-aerial is around 75,000 km^2, and its sediment fill is 500,000 km^2. The Tertiary portion of the Niger Delta was divided into three lithostratigraphic units by Short and Stauble [15], Avbovbo [16], Doust and Omatsola [17], and Kulke [10]. These units represent prograding depositional facies that are primarily differentiated from one another based on their sand-shale ratios, which range in age from Paleocene to Recent. The Akata, Agbada, and Benin Formations are among them.

Akata Formation (of marine shale origin)

The Niger Delta's base, or the base beneath the entire delta, is the marine-derived Akata Formation. Although it is made mostly of marine shale, which could be the source rock, it also has silty and sandy beds. These beds, which could serve as reservoirs in deep water, were laid down as turbidites and channel fills for continental slopes. Although the exact thickness of this sequence is unknown, it may exceed 7000 meters at the delta's center. Its formation age ranges from the Eocene to the present. Usually, the marine shale series is under excessive pressure.

Agbada Formation (Paralic clastic)

The Niger Delta's hydrocarbon-prospective sequence is formed by the Agbada Formation, which sits on top of the Akata Formation. The primary hydrocarbon reservoirs in the delta oilfields consist of the sandy portion of an alternation of sands, sandstones, and siltstones. Shale is particularly crucial for reservoir sealing. The paralic sequence, which spans the Eocene to Pleistocene in age, is found in all depobelts, much like in marine shales. The bottom of the majority of Niger Delta exploratory wells reaches these lithofacies, which can be up to 3000 meters thick.

Benin Formation (Continental Sands)

The Benin Formation, the basin's topmost region and third lithostratigraphical unit, sits atop the Agbada Formation. It is made up completely of non-marine sand that spans in age from Oligocene to Recent and in thickness from 0-2000m. After deltaic deposition shifted southward into a new depobelt, it was deposited in alluvial or upper coastal plain settings. Figure 1 depicts the three Niger Delta formations in a stratigraphic column, and Figure 2 shows the BOK field's approximate location on a Google map of the region.

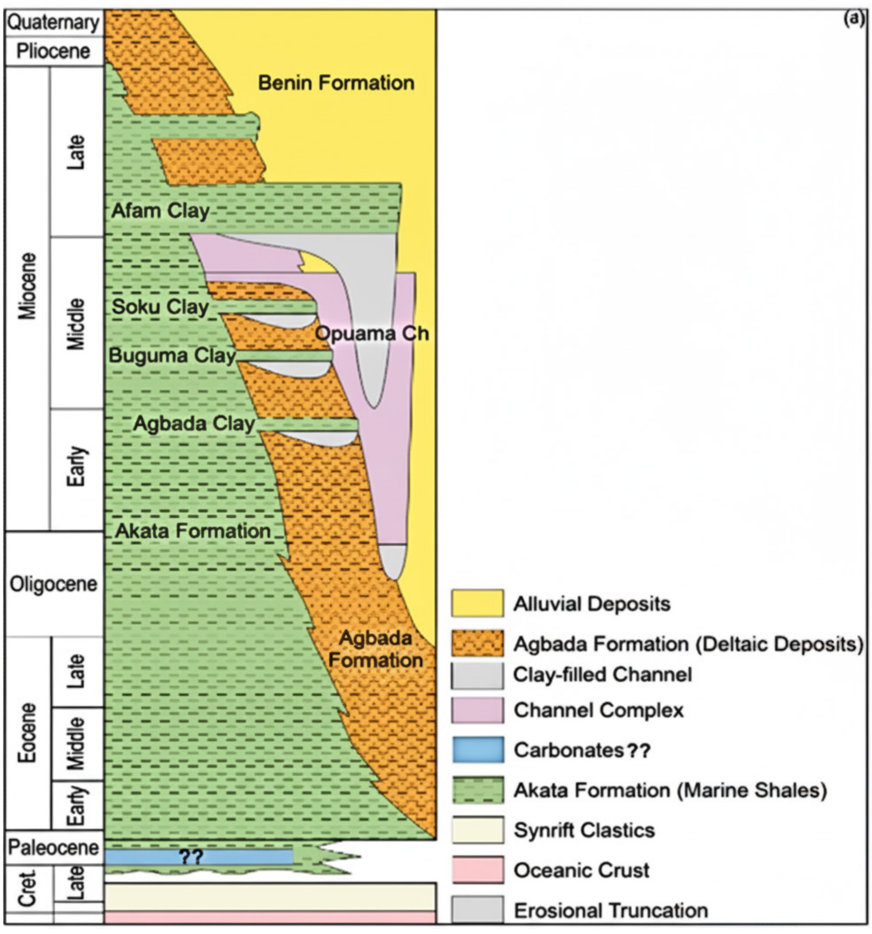

Figure 1. Stratigraphy showing the formations in Niger Delta Basin; Doust and Omatsola, 1990 [17]

Figure 2. Google Map of the Niger Delta Area showing approximate location of BOK Field

3. Geophysical Well Logs and 3D Seismic Data in Volumetric Appraisal Applications

Geophysical well logging techniques can be used to gather subsurface geological information. A log is a continuous recording of a set of curves indicating different formation qualities that are penetrated in wells, plotted against depth. A geophysical log is created by continuously recording a geophysical parameter along a borehole. Because geophysical sampling during drilling (cutting sampling) leaves a very imperfect record of the formation encountered, geophysical well logging is required. Mechanical coring is a slow and costly method of bringing entire formation samples to the surface. The coring results are clear-cut. Because it requires interpretation to elevate a record to the level of geological or petrophysical experience, logging is exact and ambiguous. But with experience, calibration, and computers, logs bridge the gap between cuttings and cores. Seismic interpretation is the technique of interpreting 3D seismic data. The science of determining the geology at a certain depth from the processed seismic data is known as seismic interpretation. Prior to the advent of strong computer systems with visual capabilities, interpretation was done by hand on sections of paper. Today, the industry uses computer-aided interpretation systems. Three related categories can be used to categorize the interpretation process:

i. Structural interpretation
ii. Interpretation of stratigraphy
iii. Lithologic interpretation

Structural interpretation: The goal of structural interpretation is to use the observed three-dimensional arrangement of arrival times to create structural maps of the subsurface.

Interpretation of stratigraphy: Connects the observable pattern of reflections to a model of a cyclic deposition episode. A chronostratigraphic framework of cyclic, genetically connected strata is to be developed.

Lithology interpretation: Uses seismic data to ascertain changes in lithology, porosity, and pore fluid. Bright spots and dark spots are examples of direct hydrocarbon indicators that are used in this lithologic interpretation method.

Petrophysical parameters

All the petrophysical dimensions of this work with the governing empirical models have been explicitly explained in Adizua et al. [3]. However, for completeness, the volumetric computational model is briefly highlighted below;

Volumetric Analysis

It is crucial to accurately estimate the reservoir's hydrocarbon reserves volumetrically. In addition to calculations from log data, this algorithm also takes into account the reservoir's dimensions and form, as well as correlations between logs from field wells. Seismic and log data let the analyst perform precise computations. The amount of hydrocarbon that can be found in a trap must first be calculated. This is achieved by defining a reservoir thickness (h) that spans an area (A) and generates a volume (V). The following empirical model by Cosentino [18] was used to compute hydrocarbon volumes:

$$\text{HCIP (Metric unit)} = A * h * N/G * \emptyset_{eff} * (1\text{-}Sw) \quad (1)$$

where,
A = Area of the reservoir prospect (obtained from seismic data)
h = Thickness of the reservoir (in meter)
Ø = Effective porosity (in fraction)
NTG = Net to gross (in fraction)
Sw = Water saturation (in fraction)

4. Materials and Methods

4.1. Materials (Data Set)

3D seismic data in SEG-Y format, well data (well header, suites of logs, well trajectory, check shot) were used to carry out this research. Table 1 shows details of the well data provided for the research.

Table 1. Available well parameters used for the study

DATA SET/WELLS	BOK - 14	BOK - 16	BOK – 19
Well header	YES	YES	YES
Well trajectory	YES	YES	YES
GR log	YES	YES	YES
Density log	NO	YES	NO
Neutron log	YES	YES	YES
Sonic log	NO	YES	NO
Bit size log	YES	YES	YES
Caliper log	YES	YES	YES
Pef log	YES	YES	YES
Spontaneous log	YES	YES	YES
Deep resistivity	YES	YES	YES
Medium resistivity	YES	YES	YES
Shallow resistivity	NO	NO	YES

An essential component of the well data information is the well header data. Individual position (surface X, Y), total depth (TD), and elevation depth (KB, DF, RT) are all included in this data. Suites of logs were sent for analysis, as indicated in Table 1. A rapid look interpretation (lithology identification, reservoir zones, and fluid discrimination) of the various log traces and quantitative interpretation was performed using the combined logs. Additionally, they were used as input parameters for seismic well tying. GR in GAPI, LLS, Rxo, Rt in ohm, RHOB IN g/cm^3, NPHI in V/V, caliper and bitsize in inches, photoelectric log in B/E, spontaneous log in mV, and sonic in us/ft were all given along with the log depth in meters. The check shot data contains information on the measured depth and one-way time at particular intervals. The most helpful logs for a successful seismic-to-well tie are those that integrate this information with density and sonic logs. In SEG-Y 8-bit digital format, 3D pre-stack depth migrated full offset seismic data was supplied. The bulk volume region for volumetric estimation was determined from seismic data, and the structural style of the field was mapped on the seismic. There were 444 crosslines and 961 inlines in the seismic data, respectively. Microsoft Excel and Schlumberger Petrel 2014 were used for data analysis. Microsoft Excel was mostly used for graphing, while Petrel exploration and production software was utilized for seismic interpretation, seismic-to-well connection, volumetric analysis, and petrophysical analysis.

4.2. Methods (Research Workflow)

Every aspect of the workflow shown in Figure 3 is discussed, and these steps were carefully followed through for the successful actualization of the focal objective for this study.

4.2.1. Data Import

The first step in performing data analysis properly is data importing. A new file is made, and the units and coordinate reference system are adjusted to correspond with the data. The relevant file type was used to import the well header, well deviation, log data, check shot, and seismic data.

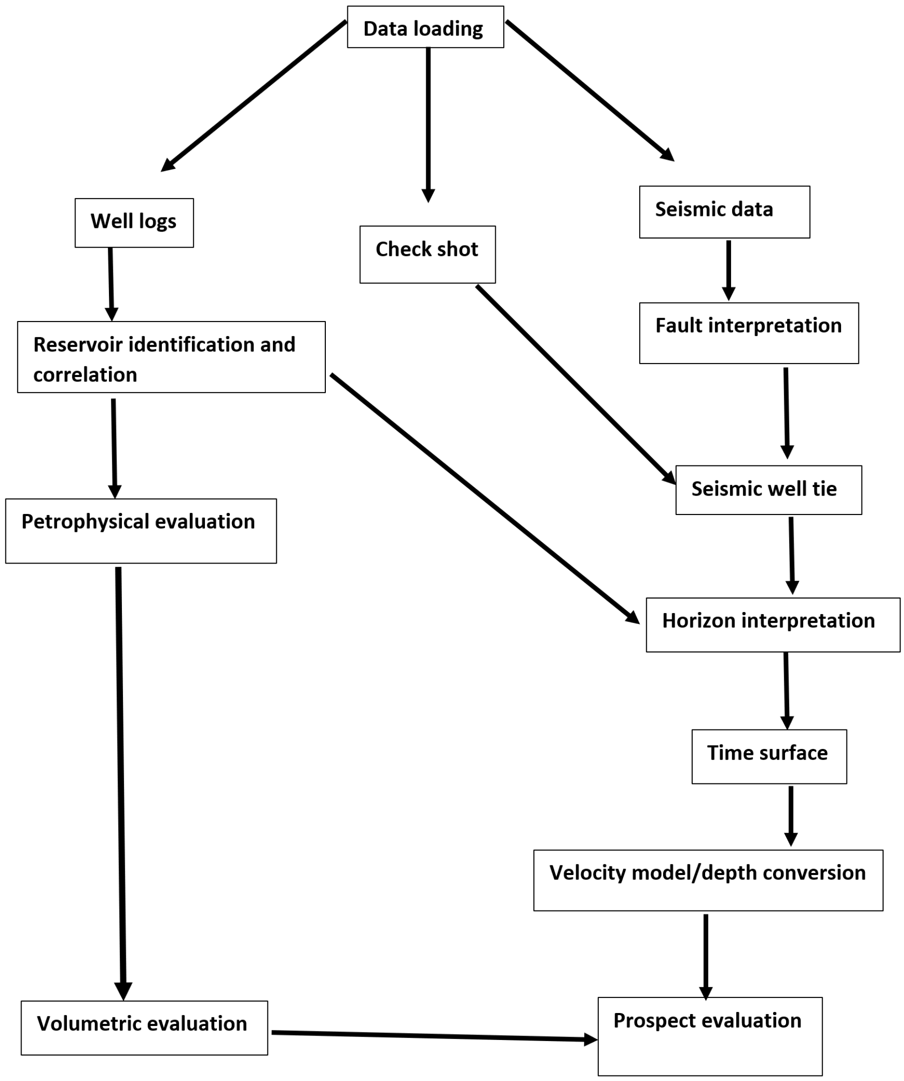

Figure 3. Research workflow for volumetric assessment and appraisal of BOK field

4.2.2. Seismic Interpretation

A. Fault picking

Faults were selected on the seismic section to define the geological structural trend of the study area, with consideration for the geology of the basin structural style. A general framework for comprehending the projected faulting pattern in the area is frequently provided by structural styles. Growth faults, major bounding faults, rollover anticlines, collapse crest structures, and synthetic and antithetic faults are the main fault trends in the Niger Delta Basin. To further illustrate the fault, variance attributes were created and selected on the seismic inline and crossline in 10-step increments. Seismic patterns, such as when a strong, continuous reflection shifts into a low amplitude zone, abrupt dip changes, and the end of reflections are all indicators of faults.

B. Well-to-seismic tie

After correlation, the interpreter uses a synthetic seismogram to perform a well-to-seismic tie. The objective is to compare the depth-domain measurements obtained from well logs with the time-domain seismic data. A well tie compares log data from the well with seismic data at a well location. Processed seismic data that provides an actual seismic trace at the wellbore site we wish to tie and from which we can estimate the seismic source wavelet is necessary to execute well-to-seismic tying. There are many logs, such as a gamma-ray and resistivity log to highlight the reservoir and pay zone, a sonic and density log for a synthetic seismic, and an integrated sonic log for time depth conversion. A synthetic seismogram is a seismic trace that is produced by convolving the extracted wavelet with the reflectivity obtained from sonic and density logs. We can match the stratigraphic sequence drilled in the well with the acoustic reflection captured on the seismic section as a consequence of the well-to-seismic tie. This allows us to objectively assess seismic features like amplitude and link borehole formation tops seen in the well with certain reflectors on the actual seismic section. We would be able to extract several seismic features to predict rock and fluid properties if the synthetic trace and the real seismic trace matched well.

C. Horizon mapping

Seismic horizon interpretation is the process of selecting and monitoring laterally consistent seismic reflectors in order to identify hydrocarbon accumulations, define their extents, and determine their volumes. Reservoir architectures, stratigraphy, and laterally consistent geologic formations were loop-tied and mapped between inline and crossline at 10-by-10 intervals. The top of the segment, where definition is often best, was used to map the horizon before working its way down.

D. Time surface generation

The input data consisted of grids created from mapped horizons. The structure map is known as a time-surface map since the horizon values are in the time domain. Convergent algorithms are used in this interpolation process on the grid.

E. Velocity modelling and time depth conversion

Velocity is a necessary piece of information to convert a time structure map to a depth structure map. Verifying structures and eliminating the inherent structural uncertainty in time are possible through depth conversion. Since velocity changes with depth, the velocity modeling technique makes it possible to generate velocity variation of each layer using velocity information from both seismic and check shots. Since the velocity model of best match produced the final residual estimate from well tops, it is a third-order polynomial.

4.2.3. Petrophysical Analysis

Emphasis would not be laid on this aspect of the workflow as they have already been introduced, explained in detail and numerically computed in a preceding paper by Adizua et al. [3].

4.2.4. Volumetric Estimation

Usually, volumetric estimates are used to assess reserves before production begins and to ascertain the true extent of the reservoir and recovery efficiency after significant production. The gross rock volume (GRV) for map-based volumetric analysis must be determined from seismic data, while wireline log readings can be used to estimate pore space, net-to-gross, and saturation. Therefore, the empirical formula from Cosentino [18], which is established in equation (1) in the previous section, was used to compute the volume of hydrocarbon in place (HCIP).

5. Results and Discussion

5.1. Well Log Interpretation

The computational details of this have already been presented in Adizua et al. [3], however for completeness, the key summary of petrophysical properties is briefly highlighted here. The result of the petrophysical analysis revealed that the average petrophysical parameters for reservoir A are 22.17% for effective porosity, 54.90% for net-to-gross, 174.61mD for permeability, and 45.15% for water saturation, reservoir B parameters are 19.24% for effective porosity, 38.66% for net-to-gross, 121.90mD for permeability, and 32.22% water saturation, reservoir C parameters are 24.23% for effective porosity, 75.40% for net-to-gross, 199.073mD for permeability, and 39.41% for water saturation and reservoir D parameters are 20.68% for effective porosity, 63.40% for net-to-gross, 157.520mD for permeability, and 27.47% for water saturation. The computed porosity and permeability for the reservoirs A, B, C and D were compared with the standard values and the results show that the four reservoirs had very good porosities and good permeability. Generally, the four reservoirs exhibit good petrophysical properties.

5.2. Seismic-to-Well Tie

Since density and sonic log are the desired input parameters for the creation of synthetic seismograms, the BOK-16 well was utilized to generate a seismic-to-well tie. Figure 4 shows the power and phase spectrum generated by the ISIS time statistical wavelet derived for the convolution process. In order to match the seismic wiggle from the synthetic seismogram and display it on the seismic section with the reservoir top defined, a bulk shift of -28 ms was applied (Figure 5).

5.3. Structural Interpretation

The seismic time slice at -2076 ms produced by the original seismic is shown in Figures 6A and 6B. Trace amplitude gain correction (AGC) does a poor job of identifying faults, while Figure 6C's variance edge attribute enhances faults more effectively. The typical seismic volume, which stresses continuity, is transformed into an analogous volume that emphasizes discontinuities via the variance attribute. Variance is typically noticed on time slices, and it's a very useful tool because it shows unidentified faults.

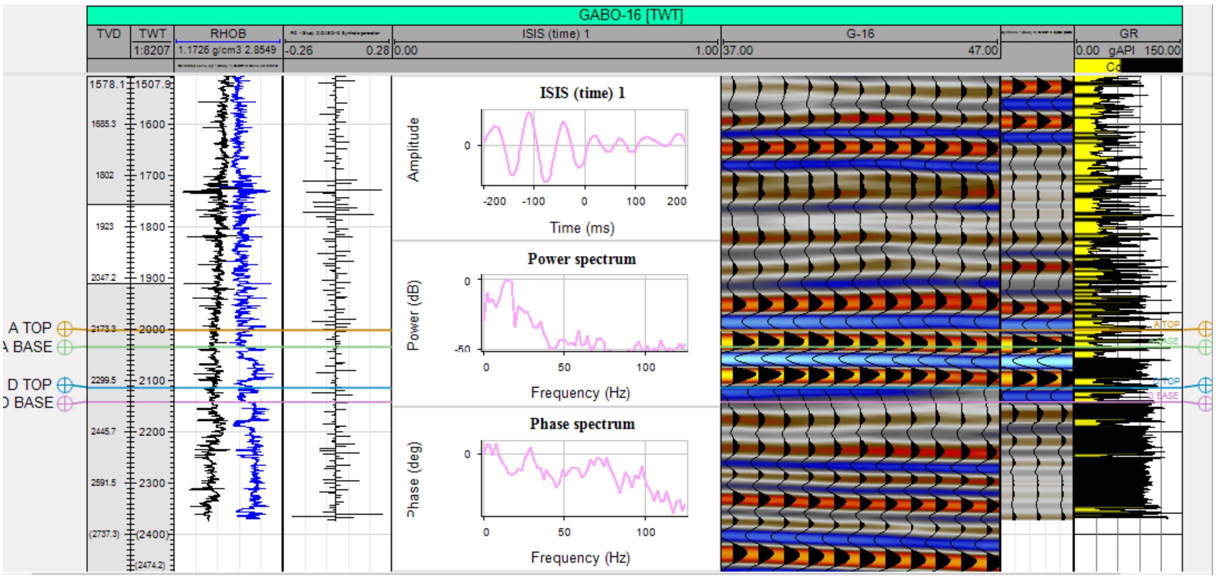

Figure 4. Seismic-to-well tie generation

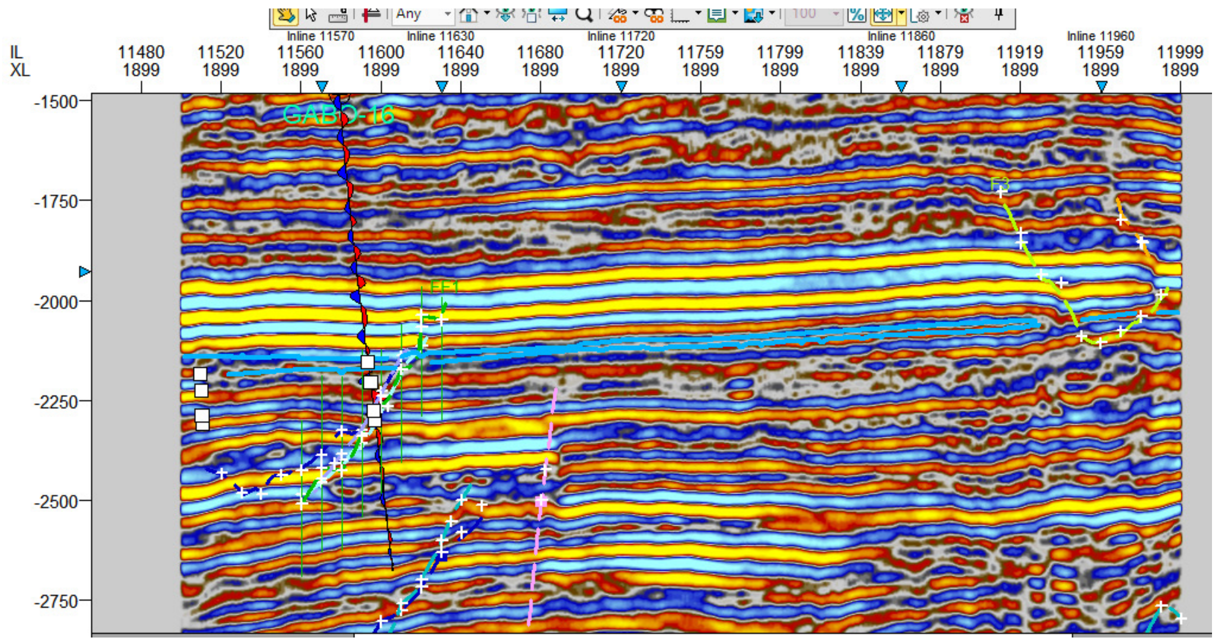

Figure 5. Synthetic seismogram displayed on the seismic section with different reservoir (white dot)

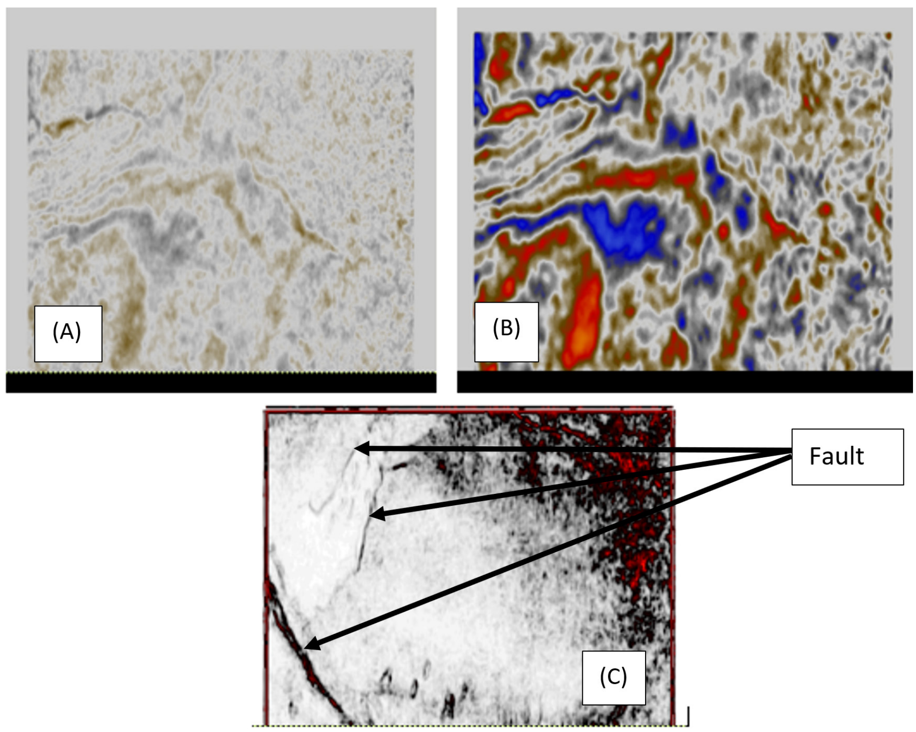

Figure 6. Structural interpretation at time slice -2076ms (A) Original seismic, (B) Trace amplitude gain correction, (C) Variance edge attribute

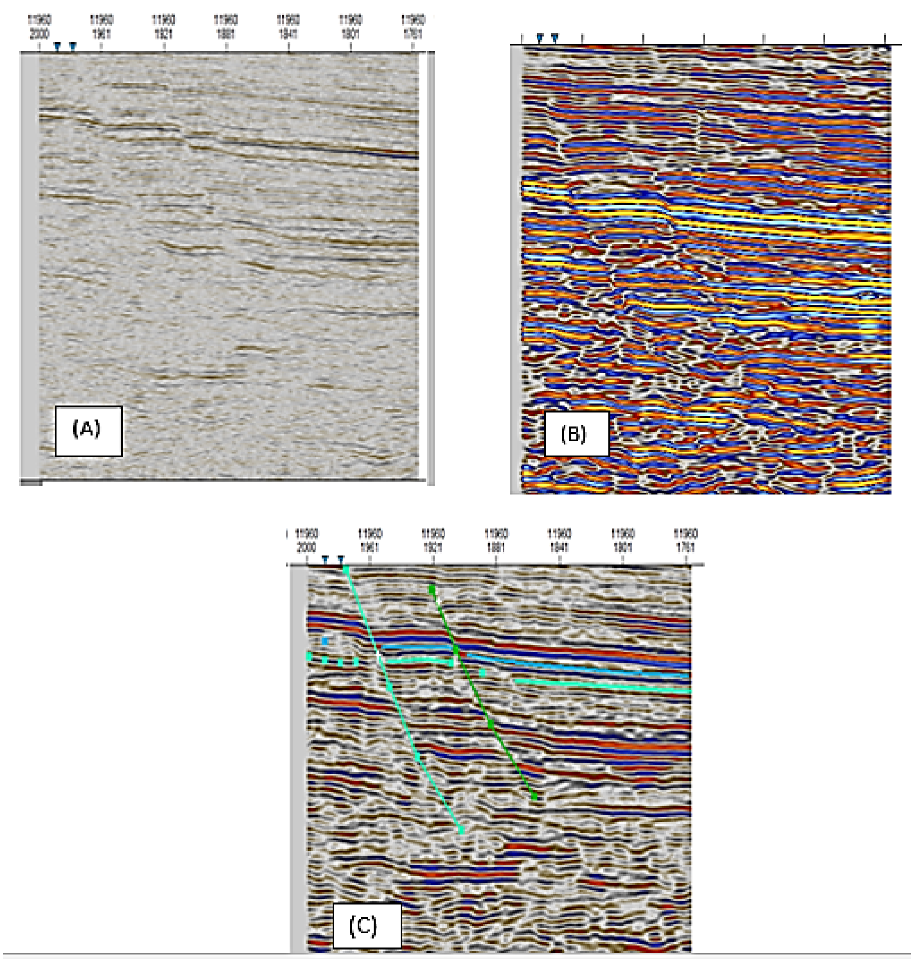

Figure 7. Structural interpretation on Inline 11940 (A) Original seismic, (B) Trace amplitude gain correction, (C) Structural smoothing

The original seismic inline 11940, with its discontinuity and relatively low seismic trace, is depicted in Figure 7A. The seismic trace and discontinuity points were enhanced by applying the structural smoothing attribute and amplitude gain correction (Figures 7B and 7C). A number of fault sticks were verified on the variance time slice after being mapped on the inline. The seismic aid horizon interpretation shows the well top. In order to identify hydrocarbon accumulations, define their extent, and determine their quantities, seismic horizon interpretation entails selecting and monitoring laterally consistent seismic reflectors. In order to map laterally consistent geologic structure, stratigraphy, and define reservoir architectures, two horizons were mapped, starting from the top of the seismic section, where definition is typically best, and moving down the section towards the zone where reflection definition is less clear by adhering to points of discontinuity on both inline and crossline. The fault trace on the horizon served as a guide for the elimination of the fault polygon. The temporal surface maps were created using the 3D grid horizon that was selected across the seismic section (Figures 8A-8B).

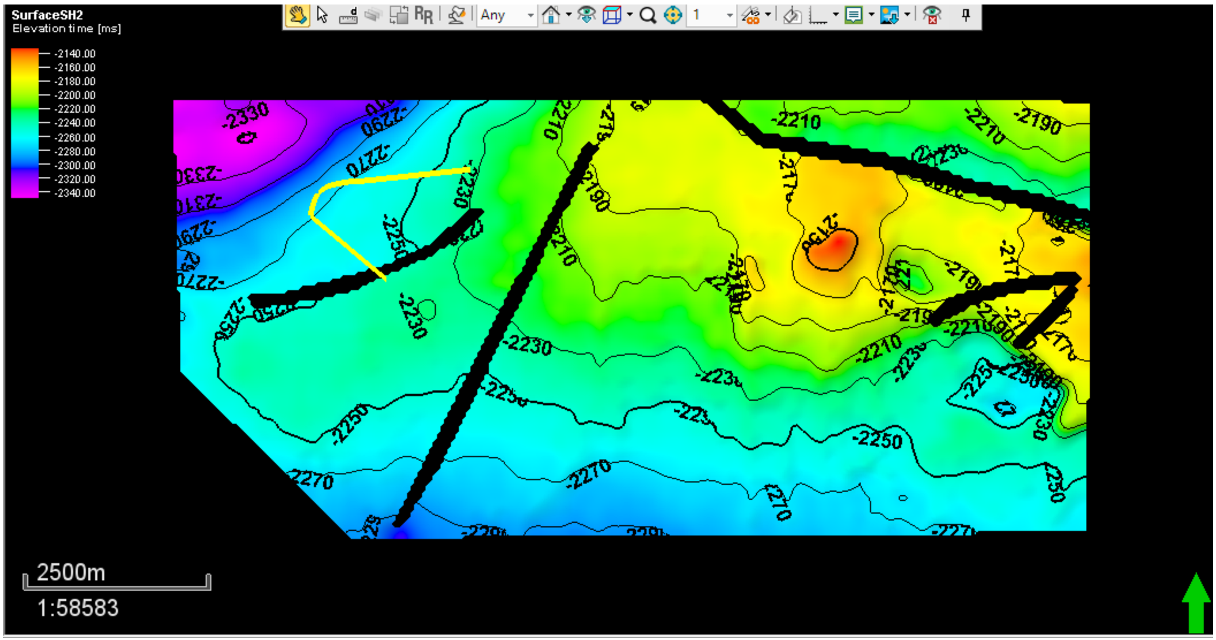

Figure 8A. Time structure map

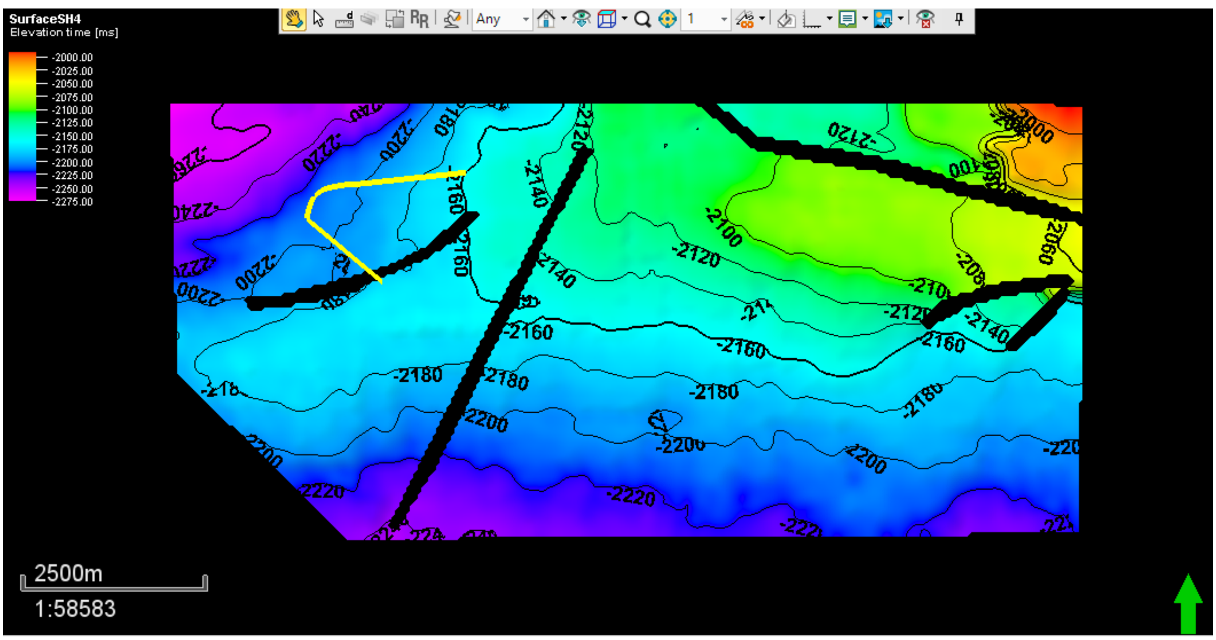

Figure 8B. Time structure map

5.4. Structural Map

Horizons A and B have different time ranges: -2140 to -2340 ms and -2000.00 to -2275.00 ms, respectively. The depth equivalents for both horizons are -2310 to -2580 m and -2120 to -2480 m.

The velocity model, which was used to convert the reservoir surface from time (ms) to depth (m), or the actual depth, to give a better picture of the subsurface, was created using the second order polynomial function, which also provided the best fit to the updated check shot produced by seismic well tie. At this point, no discernible difference was seen (Figure 9).

Anticlinal structures were seen on the depth structural map for both horizons in Figures 10A and 10B. These structures began at the red line, which represents the gas-water contact, and ended at the major fault in the northeastern direction. According to both maps, the trapping mechanisms in the BOK field are fault-assisted closure and anticlinal.

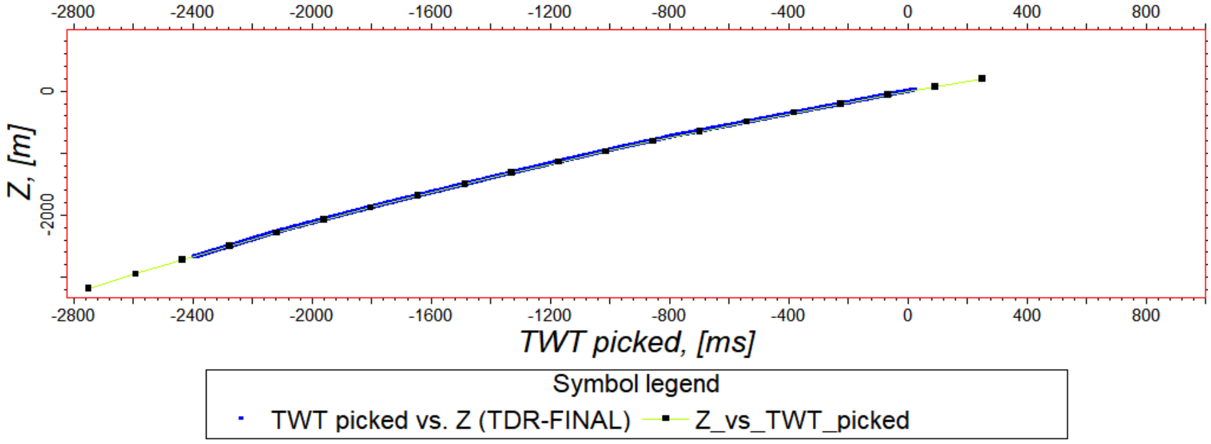

Figure 9. Velocity model utilized for converting surface from time to depth

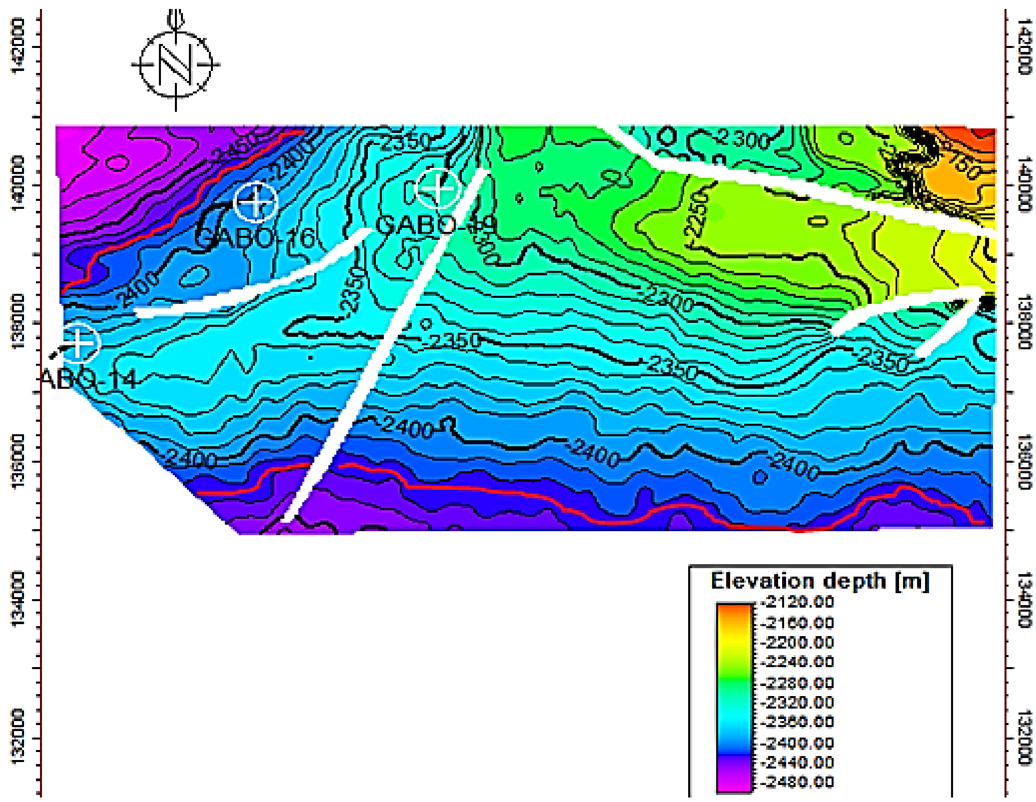

Figure 10A. Depth structure map

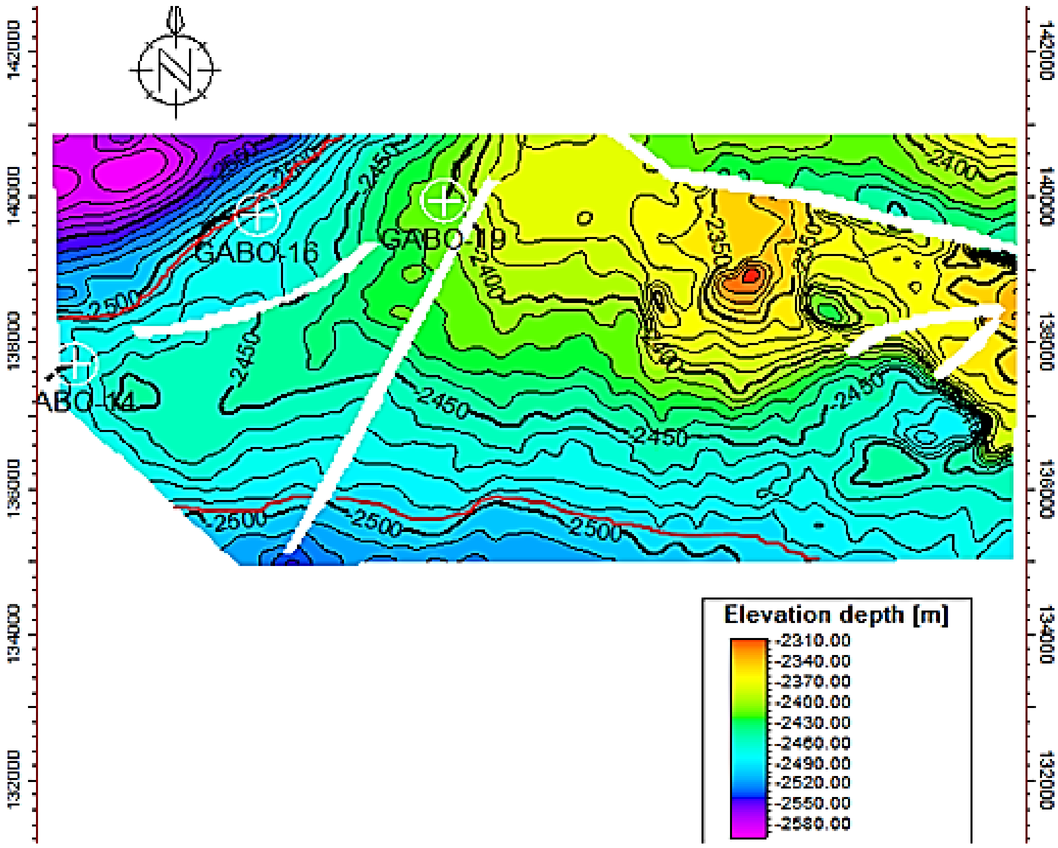

Figure 10B. Depth structural map

5.5. Hydrocarbon Volume Estimation

A static measurement of the amount of gas or oil present is given by volumetric analysis. Data on porosity, net thickness, areal extension, and hydrocarbon saturation are necessary for volumetric analysis to be accurate. There are two methods for estimating hydrocarbon volume reserves: deterministic and stochastic. The deterministic method was used for analysis in this study. In this process, a single average value of the different petrophysical parameters is chosen, and it is then entered into the HCIP formula. The prospect area on the depth structure map for horizons one and two is displayed in Figures 11A and 11B, respectively. The input petrophysical parameters, namely, net to gross, porosity, hydrocarbon saturation, average thickness, and area that were used for the volumetric estimation are presented in Table 2.

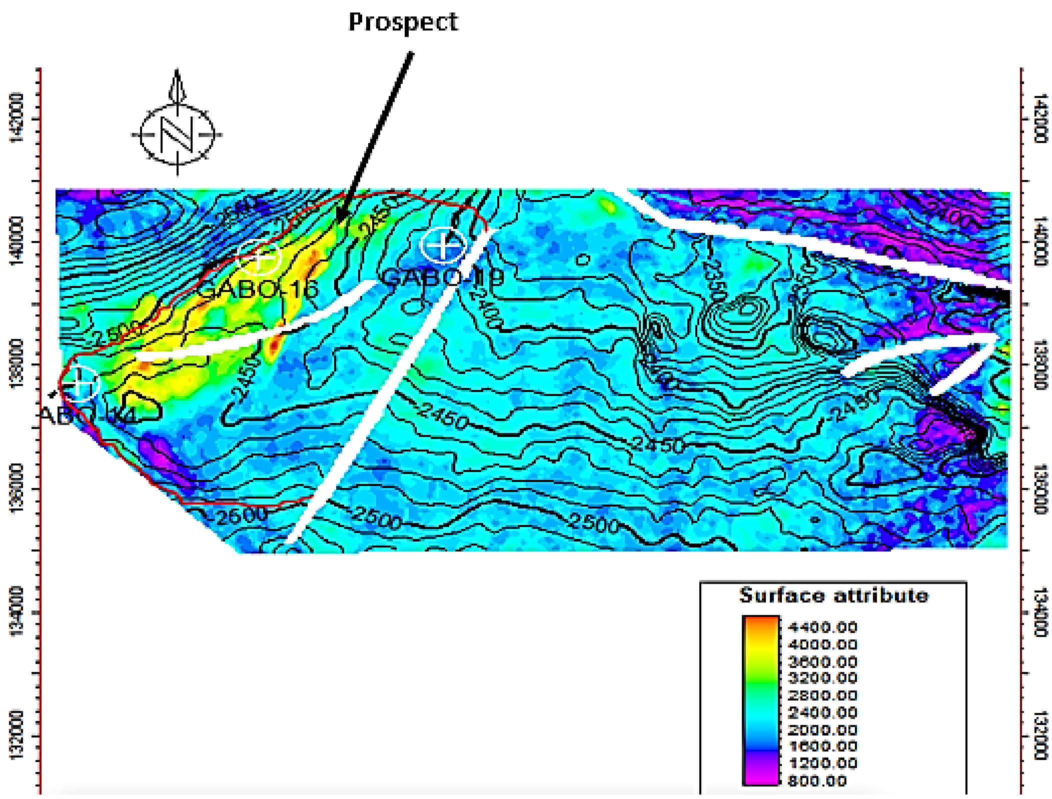

Figure 11A. Prospect area on depth structure map for horizon one

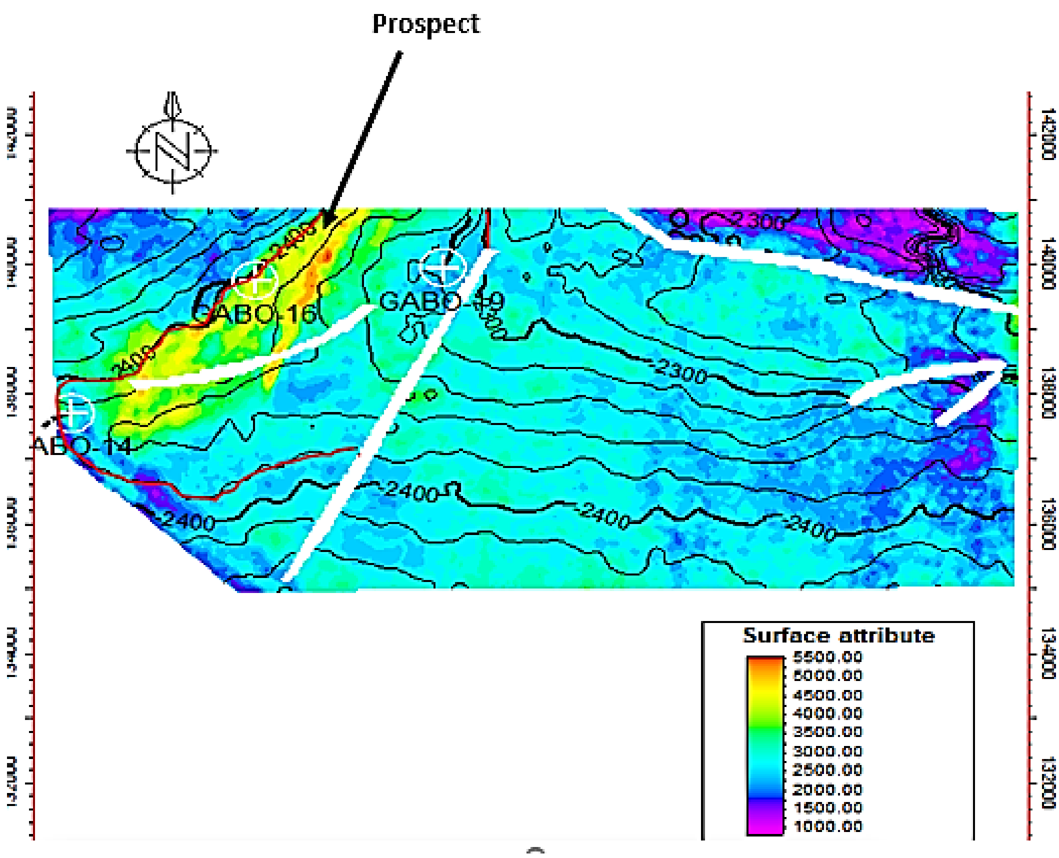

Figure 11B. Prospect area on depth structure map for horizon two

Table 2. Input data for volumetric estimation

Parameter	Values for sand B	Values for sand C
Net to gross	0.39 (%)	0.75 (%)
Porosity	0.19 (%)	0.24 (%)
Hydrocarbon saturation	0.68	0.61
Average thickness	19.15 (m)	33.51 (m)
Area	$1.52049\times10^{7}(m^{2})$	$1.30202\times10^{7}(m^{2})$

Hydrocarbon volumes were calculated using the deterministic volumetric approach, as shown below, based on the input parameter given above. Equation (1) from the previous section, which describes Cosentino's empirical relation, gives us

For reservoir B;

HCIP = 1.52049x$10^{7}m^{2}$ x 19.14667m x 0.39 x 0.19 x 0.68

HCIP = 14,669,115.94m^{3}

Conversion unit; 1 cubic meter =6.289barrels

Therefore; 14,669,115.94m^{3} =? Barrels

Thus 14,669,115.94 x 1 m^{3} =14,669,115.94 x 6.289 barrels

HCIP = 92,254.070.15 barrels = 92MMbbl.

For reservoir C;

HCIP = 1.30202x$10^{7}m^{2}$ x 33.50667m x 0.75 x 0.24 x 0.61

HCIP = 47,901,737.21m^{3}

Using similar conversion illustrated above;

HCIP = 301,254,025.5 = 301MMbbl.

The use of variance edge attributes improved structural interpretation of the seismic data by highlighting faults. Additionally, the identification of the potential region confirmed by the drilled well was facilitated by the use of the attribute Average energy. The sandstone facies' petrophysical investigation revealed that the reservoir was of good quality, with NTG values ranging from 38.66% to 75.40%, porosity values between 19.24% and 24.23%, and permeability values between 121.90mD and 199.073mD. The reservoir quality is similar to that of other reservoir systems reported by Ihianle et al. [5] in "X-Y" field of Niger Delta and Salami et al. [9] in Baze field, Onshore Niger Delta. The total hydrocarbon estimate originally contained within reservoirs B and C was estimated to be 92 million barrels of hydrocarbons and 301 million barrels of oil, respectively. The detailed computation is as presented above. These values of HCIP are quite enormous and therefore suggest that the BOK field is a very commercially viable field that should be further evaluated and possibly exploited for its huge oil and gas reserves.

6. Conclusions

Large growth faults and anticlinal fault-assisted closure, which are common in the Niger Delta Basin and cause hydrocarbon trapping, were discovered during the structural investigation of the BOK field, according to the results of the interpreted seismic data. When comparing the values obtained from the quantitative description of porosity and permeability, it is evident from petrophysical analysis that the reservoirs within the field are classified as good to very good reservoirs. As a result, these reservoirs exhibit a petrophysical parameter that is greater than that of a tight reservoir. Reservoirs B and C hold approximately 92 million barrels of hydrocarbons and 301 million barrels of oil, respectively. The BOK field is a highly commercially feasible field that should be further assessed and potentially exploited for its significant oil and gas potential, as shown by these HCIP values, which are quite large.

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Conflict of Interest

The authors declare no conflict of interest.

Authors Contributions

With the first author serving as team lead, the authors planned and designed the work and processed, analyzed, and interpreted the data. While the first author reviewed, edited, and revised the manuscript to its current state and is currently the lead/corresponding author, the second and third authors, respectively, wrote the paper's first and second drafts. The present version of the work was approved by all authors.

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