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Full Length Research Paper

Geostatistical modeling of interval velocity to quantifying hydrocarbon resource in multi-layer reservoir from TMB field, Niger Delta

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Geostatistical modeling is performed on the "TMB field" in the offshore area of Niger Delta using 2D seismic data. The goal of the study is determine interval velocity by using geostatistical modeling; and calculate the volume of the reservoir according to different Oil-Water-Contact (OWC) whose uncertainty was characterized by a given probability distribution. The models are completely consistent with the observed vertical and lateral distribution of the structural and petrophysical parameters. The probability distribution of Stock Tank Oil Initially In-Place (STOIIP) is obtained with 3D operator layer-based inversion scheme. After the modeling, estimation of unbiased volumes is carried out and the risk associated with the volumes is quantified. Regression analysis based on geologic zones showed that geological and petrophysical modeling results exhibit a correlation between increasing N/G and increasing STOIIP, as well as between the increasing porosity and increasing STOIIP. STOIIP increases as the value of N/G and porosity increase. The major steps in the geostatistical modeling procedure are illustrated with an example of depth conversion from the TMB field. This study shows that it compares favourably with other techniques like linear velocity modeling.

Key words: Probability distribution, geostatistical modeling, reservoir property, porosity, water saturation, gross rock volume, interval velocity, net-to-gross.

INTRODUCTION

The TMB field is located in transitions zone of Niger Delta, Nigeria (Figure 1), and has been producing since 1970s. Niger delta comprises of the Tertiary age siliciclastic deposits which are attributed to three lithostratigraphic formations, the Akata, the Agbada, and the Benin Formations. The Akata Formation (marine shales) is characterized by uniform pro-delta shale, which in general is dark grey, medium hard, and contains, especially in its upper part, plant remains. The boundary to the overlying Agbada Formation is defined by the first appearance of deltaic sandstone beds (Avbovbo, 1978).

The Agbada Formation (Paralic cycles) comprises the majority of the oil and gas reservoirs of the Niger delta, and is composed of alternating sandstone/ shale bedsets representing the delta front, distributary channels and the deltaic plain. The upper part has a higher sandstone content than the lower part, demonstrating the progressive seaward advance of the Niger delta though geological time. The Benin Formation (Continental sands) consists of massive, highly porous sandstones with a few minor shale interbeds indicating an alluvial (braided river) environment. Deposition occurred in a continental upper deltaic environment indicated by a lack of marine fauna. This provides good quality reservoirs but no seals.

To the north of the study area, the macrostructure is bounded by a major E-W macrostructural boundary fault, which controlled the depositional and structural history of the TMB field. The field structuration is characterized by a rollover anticline, with a dip closed and fault/dip trapping mechanism for the reservoir layers (Avbovbo, 1978). The deltaic sedimentary sequence has built out basin ward in a S-SW direction, perpendicular to the main growth fault trend. The main reservoir facies comprising upper shoreface, lower shoreface and distributary channels that have been deposited in a shallow marine environment (Chukwu, 1991). The upper and lower shoreface deposits

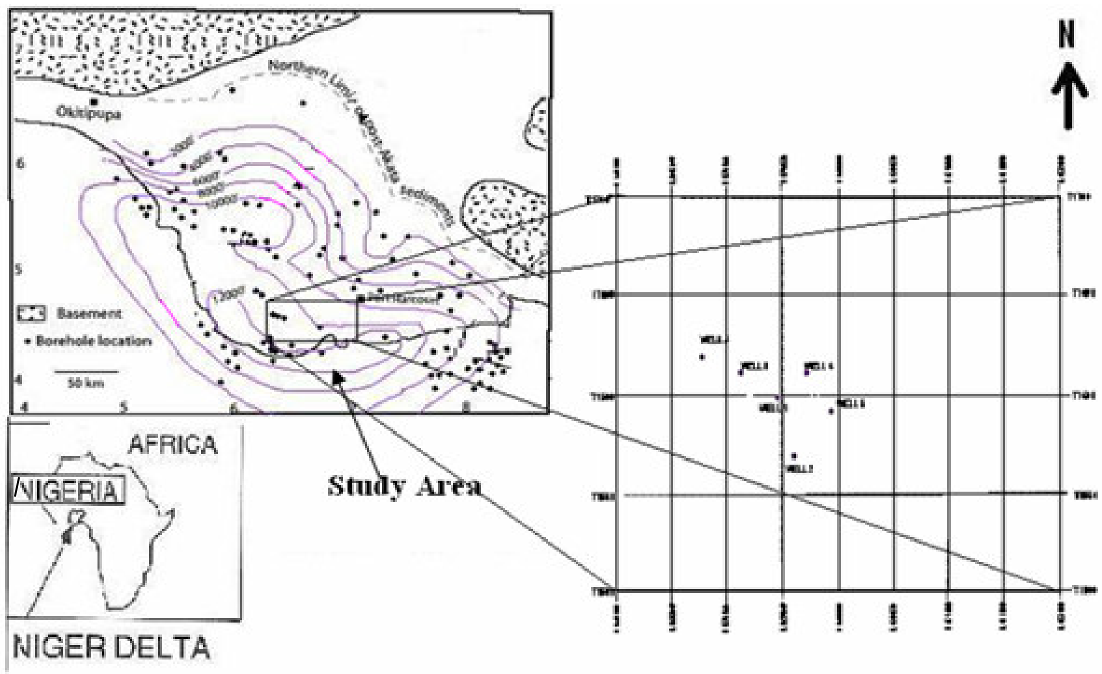

Figure 1. Location of TMB Field in thickness isopach contours (km) of Agbada Formation (modifield from Avbovbo, 1978) and inset basemap showing the seismic lines and the well location.

form elongated W-E trending sand bodies along the palaeo-coastline with reservoir quality degrading in a basin ward direction (Southerly and Southwesterly direction) (Evamy et at., 1978). Distributary channels form primarily N-S orientated sand bodies with sharp lateral boundaries. They are commonly positioned on top of or are cutting into the shoreface sequence. Sedimentary packages are thinning over the crestal part of the collapsed crest while they become thicker towards the south (Avbovbo, 1978).

MATERIALS AND METHODS

Field location and data descriptions

The modeling technique is illustrated on TMB oil field located in the southern transition zone of Niger Delta as shown in Figure 1. The field is composed of 3 reservoirs that constitute a large anticline structure that is oriented North-East South-West. The presence of a large number of normal faults, clearly visible on seismic sections, has to be integrated in the modeling approach, as they are important in the delineation of hydrocarbon contact domains. Each reservoir has a different OWC resulting from the production history. The data available is comprised of 2D interpreted seismic sections and 5 wells (Figure 1). Some form of wireline-log data are available for all the wells in the study area, majority of logs are neutron –density logs, Resistivity logs, gamma-ray and SP logs. The most useful porosity tool in this reservoir is the acoustic log.

The reservoir is composed massive, well-sorted, high porosity sands forming turbiditic channels system of the Tertiary (Eocene/Paleocene). In the area of study, there are two fluid contacts OWC (Oil-water contact) and GOC (Gas-oil contacts). The objective of the multi-layer reservoir modeling is to develop a multi-layer field modeling that can be applied to new data set when available so as to continually update the volume calculations. Porosity is one of the important properties that are used in the estimation of volume. Porosity is a significant influence on the seismic velocity of sedimentary strata (Oliver et al., 2001). Pratson et al. (2003) used a sequence of established petrophysical formulation to predict porosity and velocity from clay content alone. This paper presents the geological structure and the petrophysical parameters modeling, calculations of volume according to different OWC, and estimation of uncertainty from the geological structure and petrophysical parameters using probability distribution.

The main sources of uncertainty come from the reservoir's geological structure, the variability of petrophysical properties and the OWC and GOC locations (Hampson et al., 2001; Hatchell, 2000). The probabilistic distribution of Gross Rock Volume (GRV) (MMcu.m) and Stock Tank Oil-in Place (STOIIP) (MMbbls) can then be obtained and used to get unbiased volume estimates and to quantify the risk associated with them (Hirsche, 1997).The limits between the geological units are defined through geological interpretation and seismic time picking during reservoir modeling. The seismic input to the proposed technique is 2D depth maps of the picked seismic markers shown in Figures 2 and 3. From these 2D maps, a fully consistent 3D reservoir model was built.

The geostatistical modeling approach is used in a workflow (Figure 4) that helps define the interval velocity within multi-layered reservoir for a test seismic and well datasets (Kalkomey, 1997). It is hoped that geostatistical approach to reservoir modeling can help to minimize the interwell uncertainty and uncertainty because of well deviation (Mcdonald et al., 1982). The flow divides into two main areas namely geological structural modeling and petrophysical

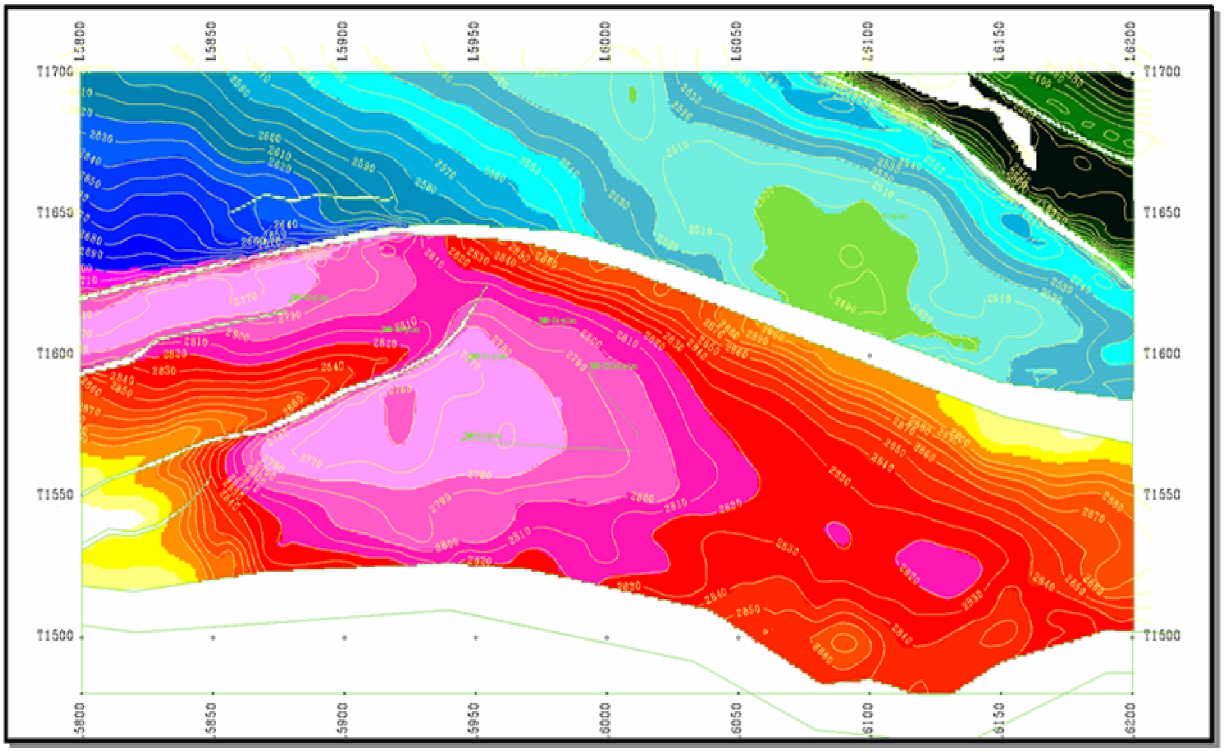

Figure 2. Depth structure map of layer-cake reference surface (top layer reservoir A).

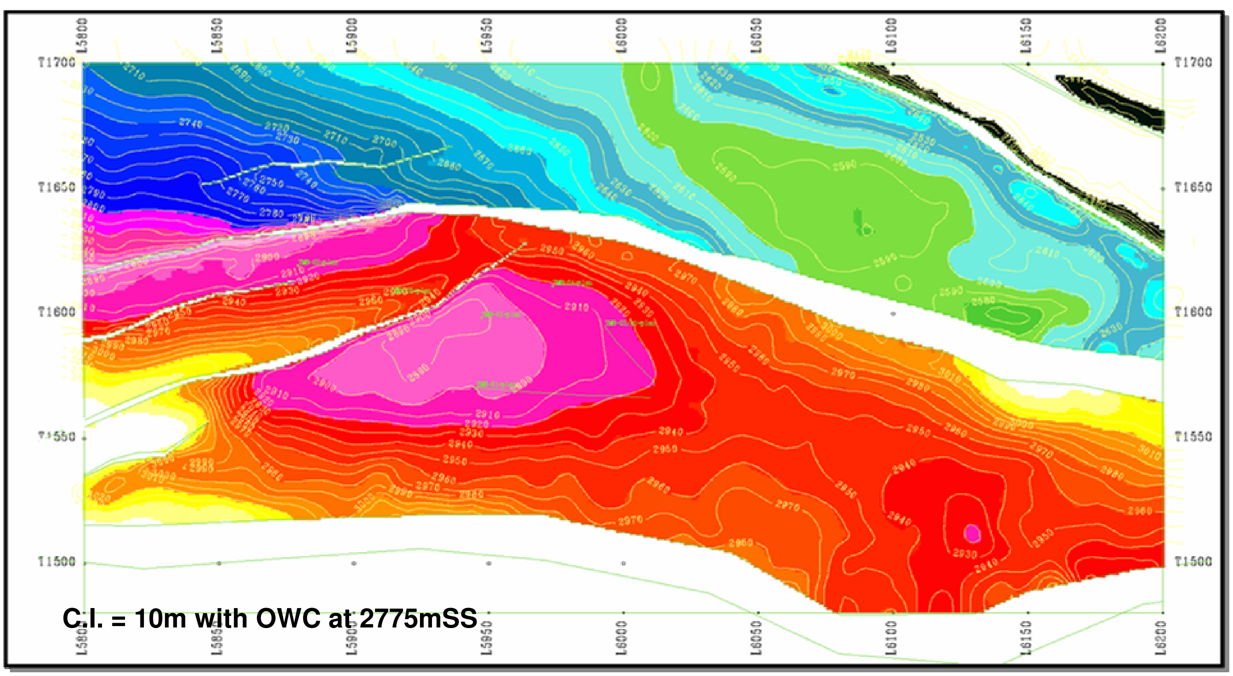

Figure 3. Depth structure map of layer-cake reference surface (top layer reservoir B).

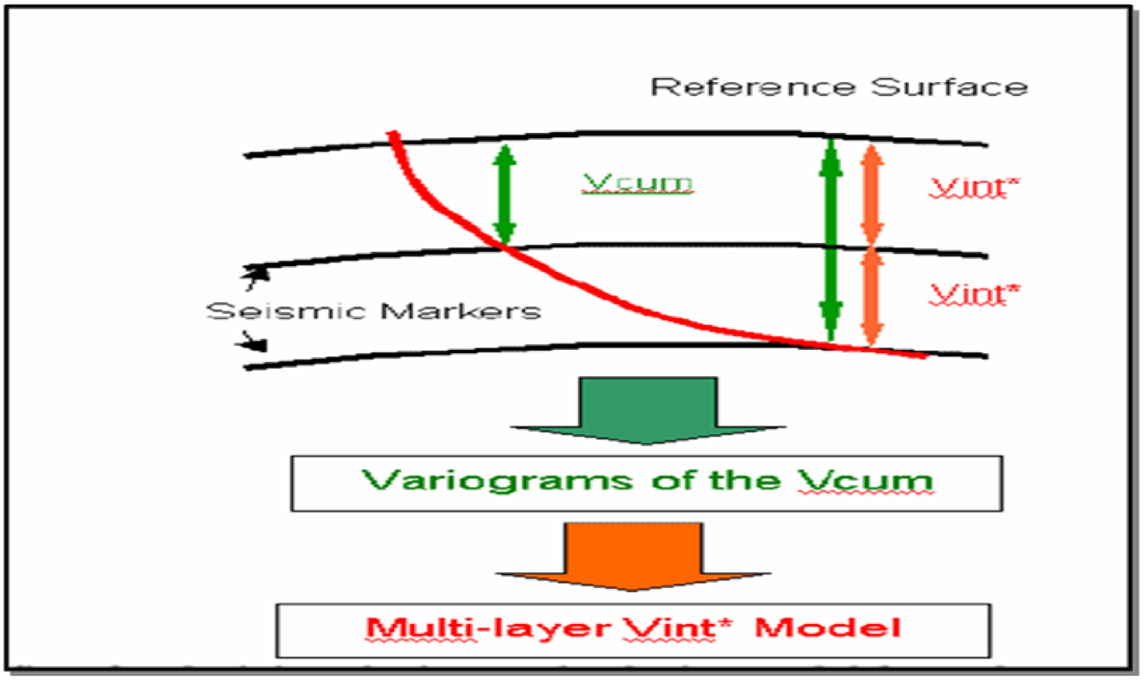

Figure 4. Workflow for deriving the interval velocity model from the cumulated velocity.

modeling.

Modeling the geological structure

When dealing with a layer cake type field, it is possible to go further than standard sequential techniques, by considering the spatial correlation between all the layers simultaneously using a multivariate variogram model. The standard approach when dealing with such a field is to sequentially krige the individual layers from the top down (Journael, 1997). Although, this kriging method treats the layers independently but cumulates the errors made in the preceding layers and thus the smoothing effect is even more noticeable when going deeper into the layer cake system. The interaction between the different layers as shown in Figure 5, the correlation between interval velocities is ignored. All layers are treated simultaneously in order to provide an optimal estimate of the interval velocities or thickness for the whole layer cake system.

Figure 4 shows the generalized procedure that is used to estimate the interval velocity and apply the results to estimate volume and carry out depth conversion. This is with a view to preparing a distribution chart of volume of hydrocarbon-in-place obtained from simulation. The results of the modeling of geological structures and petrophysical parameters are presented in form of maps and graph that were developed through a series of systematic steps, including:

(i) The reference surfaces of the whole layer cake system are calculated from wells and seismic data using standard kriging techniques.
(ii) The surfaces on logs that correspond to seismic markers are calculated using this global multivariate time to depth conversion method (Box, 2004). The interval velocities (Vint*) are cokriged from average velocities (Vav) at the wells intercepts using the respective time maps as external drifts (Figures 2 and 3).
(iii) The surfaces of the intermediate layers (geological zones) are then calculated using a collocated cokriging method (Journael 1997). The thickness of each intermediate layer is cokriged from cumulated thickness at the wells intercepts. The total thickness between the two seismic markers are the variable used in collocated cokriging so that the intermediate layers respect both the well and seismic data.
(iv) Fault surfaces are interpolated between the digitized fault polygons of the two seismic markers. They are later applied to constrain the intermediate zones and reproduce the observed throws.

Modeling of the petrophysics

The petrophysical parameters: net (reservoir rock) to gross (interval) ratio (N/G), porosity Φ and oil saturation (S_0) are assumed independent from one geological zone to the next (Hampson et al., 2001). Thickness, N/G, porosity Φ and oil saturation (S_0) parameters were estimated for each geologic zone within the reservoir in each of the three wells. Average values of the reservoir parameters were calculated over each well column (White and Simms, 2003). The resulting well “averages” for each parameter were then averaged and weighted aerially across the reservoir using the equations below:

$$\overline{h_G} = \frac{\sum h_G}{n} \quad \text{Area average of gross thickness} \qquad (1)$$

$$\overline{N/G} = \frac{\sum h_N}{\sum h_G} \quad \text{Averaged over the vertical interval} \qquad (2)$$

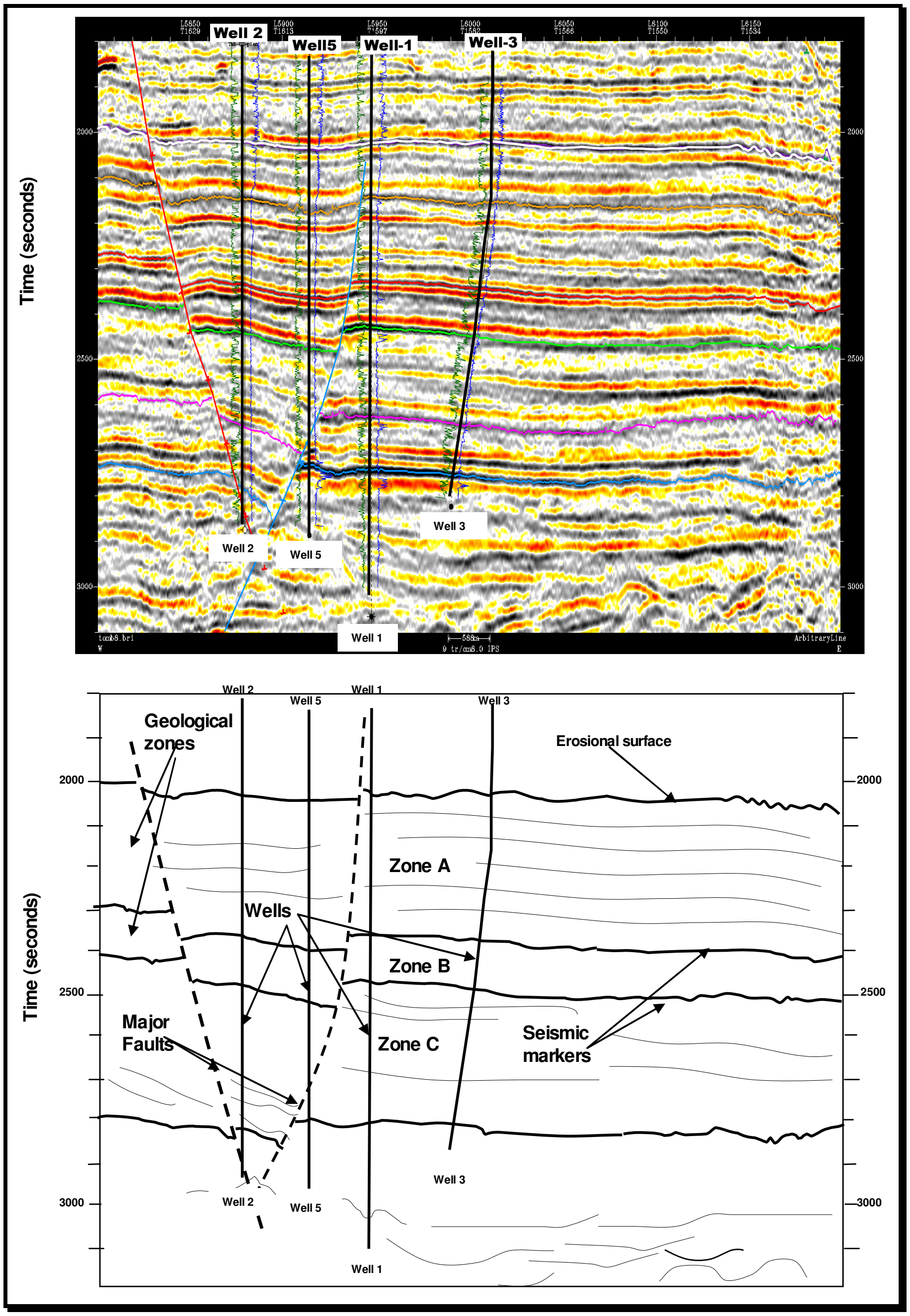

Figure 5. (a) NW-SE Seismic section through Wells 2, 5, 1 and 3, (b) Interpreted NW-SE Seismic profile through Wells 2, 5, 1 and 3 showing the seismic markers and the geological zones.

$$\bar{\phi} = \frac{\sum \phi h_N}{\sum h_N}$$ Averaged over the full vertical interval (3)

$$S_h = \frac{\sum S_h \phi h_N}{\sum \phi h_N}$$ Averaged over the hydrocarbon bearing interval (4)

Where,

h_G = Gross thickness

h_N = Net thickness

φ = Porosity

S_h = Hydrocarbon saturation

N = Number of wells

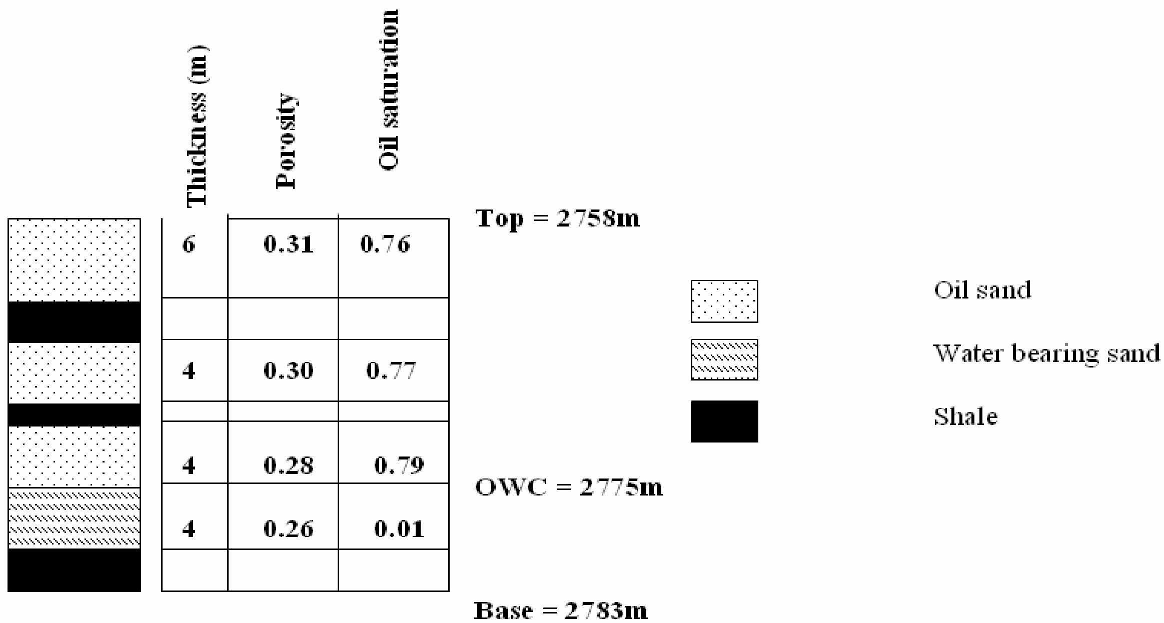

Figure 6. Reservoir properties over well 1 column.

Average reservoir properties were calculated from the reservoir properties over each well column (Figure 6) as shown in below:

$$\sum h_G = 24m$$
$$\sum h_N = 18m$$
$$\sum \phi h_N = 5.22m \ (Full \text{ int} erval)$$
$$\sum h_N = 14m \quad (Oil\ oil\ bearing \text{ int} erval)$$
$$\sum \phi h_N = 4.06m \ (Oil\ oil\ bearing \text{ int} erval)$$
$$\sum S_o\ \phi\ h_N = 3.18m \quad (Oil\ oil\ bearing \text{ int} erval)$$
$$\overline{N/G} = \frac{\sum h_N}{\sum h_G} = \frac{18m}{24m} = 0.75$$
$$\bar{\phi} = 0.31$$
$$S_o = 0.75$$

Calculation of volumes

The geological structure and the petrophysical parameters are simulated within predefined polygonal areas to calculate volumes and perform risk analysis. The interaction between the variables is considered by performing the simulations within nested loops on the following categories: erosion surfaces; reference surface; surfaces of the seismic layers; and petrophysical parameters. The water saturation and porosity are algebraically derived from the height above the oil-water contact (OWC).

Gross rock volume (GRV) and stock tank oil initially in place (STOIIP)

In order to calculate STOIIP in the structural maps of top reservoir and base reservoir shown in Figures 2 and 3, Area vs. depth method was adopted where the area enclosed by the top and the base of the reservoir were plotted against depth. The area enclosed by each contour line on the top and base reservoir maps were measured with a planimeter. The results were plotted against depth to produce lines representing the top and base of the reservoir. The total volume occupied by the reservoir, the GRV that was arrived automatically by integrating the graph after the OWC were drawn as horizontal lines at the appropriate depths. The distribution of possible volumes is derived for each layer individually (Table 1). STOIIP (MMbbls) were calculated according to the following equation:

$$\text{GRV(MMcu.m)} = A * h$$

$$\text{where} A = \text{Area and } h = \text{thickness}$$

$$\text{STOIIP} = \frac{A * h * N/G * \phi * S_o}{B_{oi}} \quad (5)$$

$$where\ B_{oi}\ \ oil\ \ formation volume\ factor$$

Uncertainties in volume estimates

The accuracy of the final estimates of volume is always dominated by the uncertainties of the reservoir model. The main factors causing uncertainties in volume estimates are structural uncertainties (dip error, limitation of seismic resolution, fault position as a result of limited number of wells, e.t.c); stratigraphic uncertainties (variation in rock development) and accumulation uncertainties (position of OWC).

The uncertainties associated with each of the input parameters to the volumetric calculation (thickness, N/G, porosity, and S_o) were expressed in terms of the probability density function. This describes

Table 1. Low-mid-high deterministic oil volume estimate.

	Geologic A			Geologic B			Geologic C		
Area of Closure (MMsq.m)		1.69			3.69			3.1	
Max Hydrocarbon Column (m)		20			36			53	
Geometry Factor (%)		0.34			0.49			0.45	
Gross Rock Volume (MMcu.m)		11.64			6287			73.61	
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Net/Gross (%)	0.35	0.55	0.75	0.35	0.55	0.75	0.35	0.55	0.75
Porosity (%)	0.25	0.28	0.31	0.24	0.27	0.3	0.23	0.26	0.29
Saturation Oil (%)	0.67	0.72	0.75	0.7	0.75	0.805	0.61	0.66	0.71
Fm Volume Factor (%)	0.77	0.8	0.83	0.64	0.69	0.74	0.71	0.74	0.77
STOOIP (MMbbls)	3.3	6.45	10.92	15.75	31.18	52.7	16.25	32.39	55.03

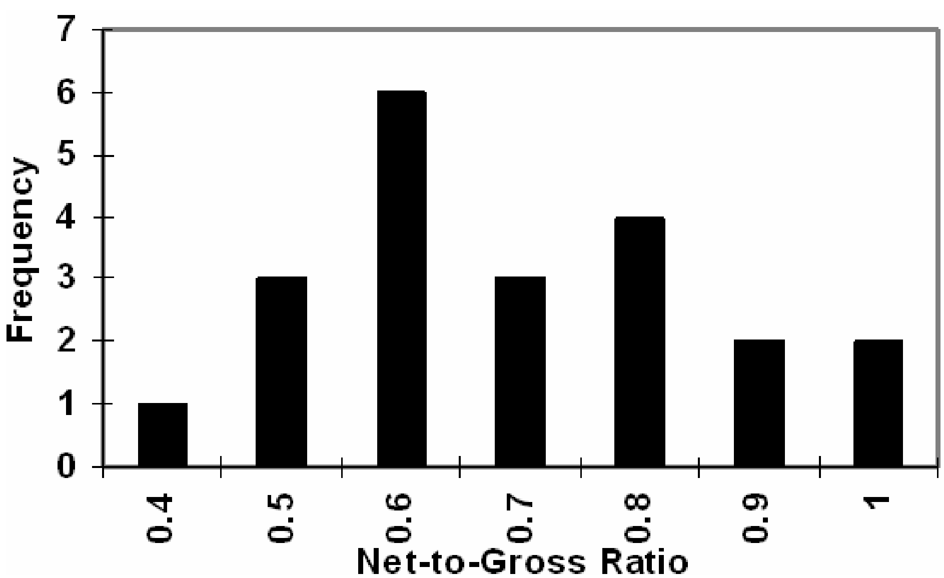

Figure 7. Histogram of a normal score transformation of net to gross data.

the range of values which may be taken by a particular parameter, along with the probability that each has of occurring. All the values for each parameter were arranged in a frequency distribution histogram. The data are transformed into normal scores (Figure 7), so as to reproduce the dissymmetric distribution observed for the layers. The corresponding probability density function was obtained for each parameter by fitting a smooth function to the histogram and the probability density function normalized.

Dependence

The input variables may exhibit a degree of dependence. Dependence was incorporated into the calculations by means of a correlation coefficient, which is a measure of degree of dependence between two variables, N/G, porosity, S_o and STOIIP. The correlation coefficient, r, ranges between -1 and 1. A semi qualitative approach was adopted to assess the degree of dependence of two variables. The following scale was used for the semi-qualitative approach:

(i) ± 0.10 very weak dependence
(ii) ± 0.25weak dependence
(iii) ± 0.50 moderate dependence
(iv) ± 0.75 strong dependence
(v) ± 0.90very strong dependence4

RESULTS AND DISCUSSION

The more important influence on the interval velocity and oil volume estimates is the porosity which is linked to the oil saturation (Table 1). The estimation of GRV and porosity from interval velocity derived from seismic inversion is feasible due to the fact that there is a good relationship between velocity and thickness as well as velocity and porosity. The results of the modeling of geological structures and petrophysical parameters with volume estimation are shown in Figures 8 and 9 for each layer whose depth structure maps are shown in Figures 2 and 3. Map of GRV illustrate the spatial distribution of

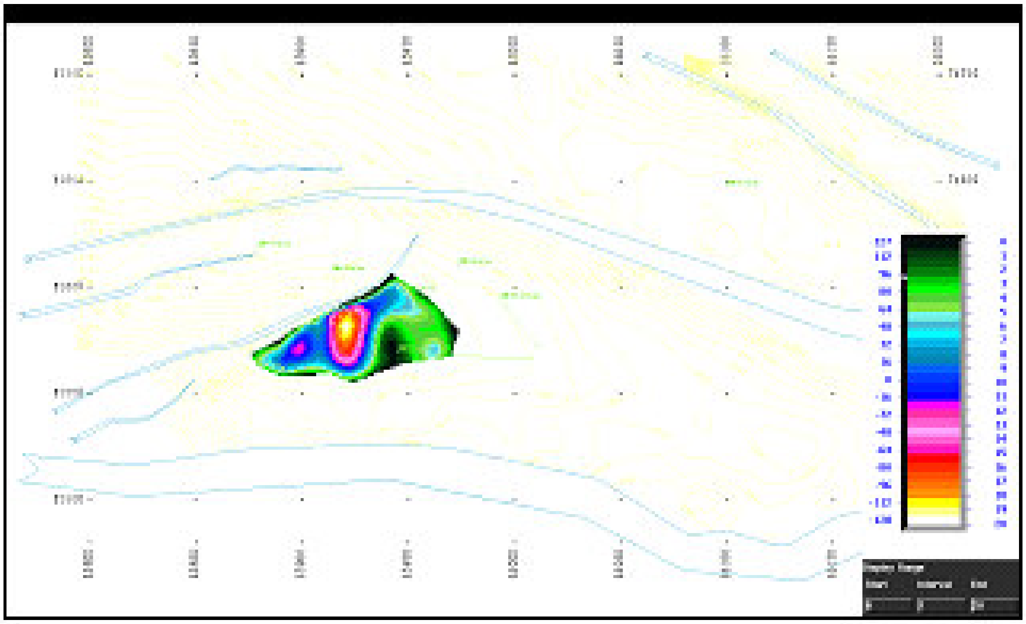

Figure 8. Distribution of Gross Rock Volume (GRV) of reservoir A obtained from simulation.

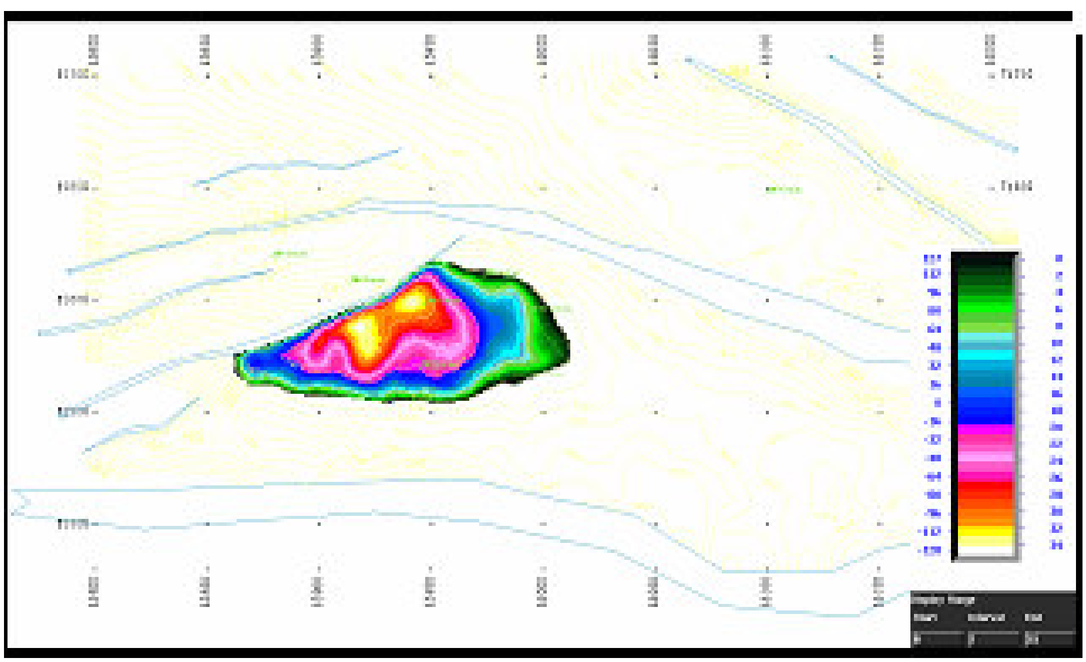

Figure 9. Distribution of Gross Rock Volume (GRV) of reservoir B obtained from simulation.

gross rock volume for each geologic zone. The Geologic zone A map (Figure 8) indicates highest rock volume in the updip central part of the field. The Geologic zone B map (Figure 9) indicates highest rock volume in the updip central part of the field. Figure 10 exemplifies graph showing the distribution of volume, obtained from simulations.

Table 1 shows the results of modeling both the petrophysics and geological structures. The listed values are for the three geologic zones forming the layer cake.

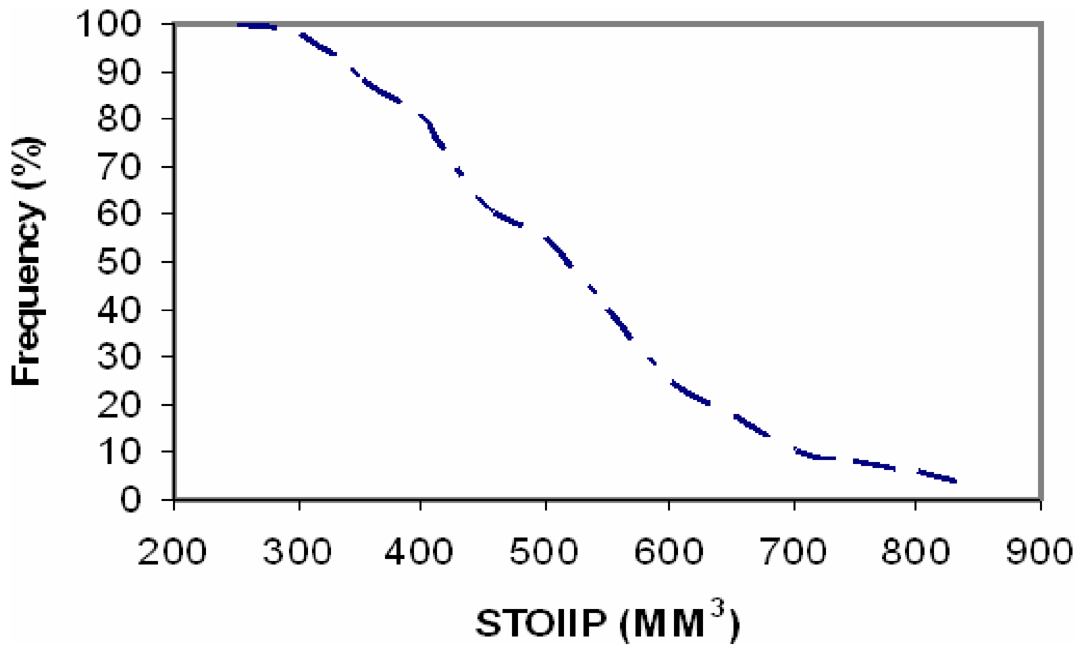

Figure 10. Graph showing the distribution of volume obtained from simulations.

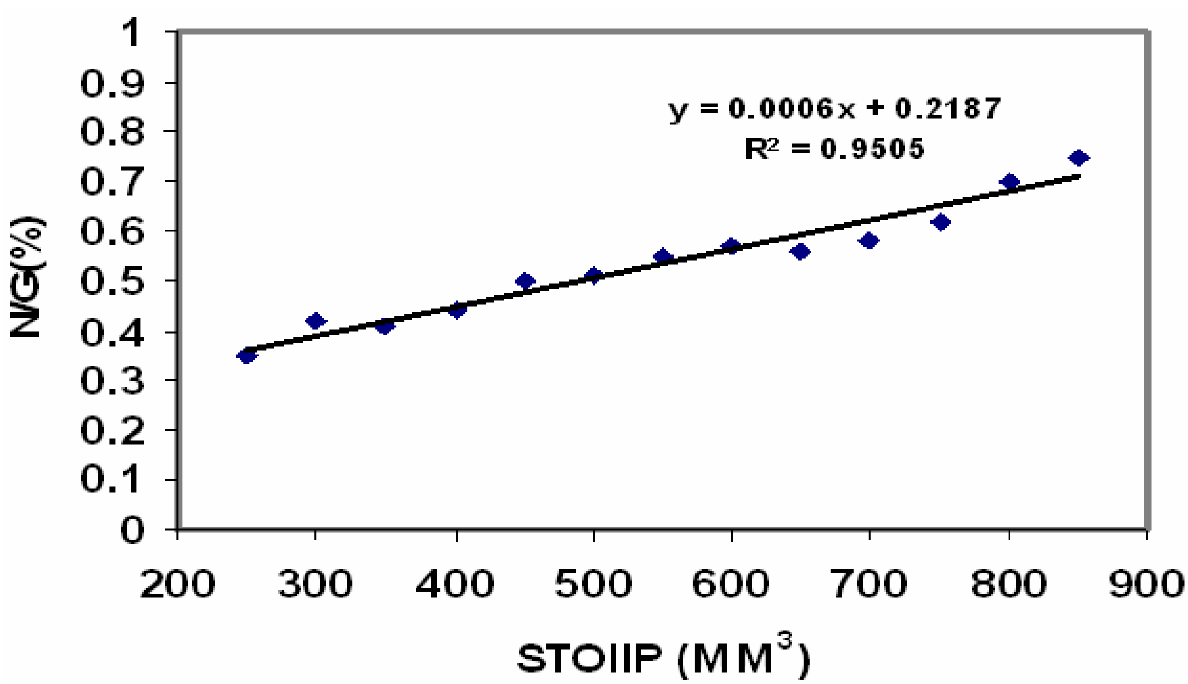

Figure 11. Graph showing the degree of dependence of STOIIP on N/G for geologic zone A.

Quantifying the uncertainty on volumes or structural model is an important objective, but the characterization of the impact on the uncertainty of a few key parameters is equally important either at the exploration, appraisal or production stage. Simulations are performed on only one of the above sources of uncertainty that is, petrophysics, and the other ones being considered as known (base case). This allows for a study of the sensitivity and hence quantifies the influence of just one particular group of parameters on the volumes. To determine the N/G – STOIIP and porosity-STOIIP dependence, N/G versus STOIIP was plotted for Zone A for one well (Figure 11) and porosity-STOIIP plot colour-coded by geologic zone (Figure 12). Good correlation can be seen between N/G

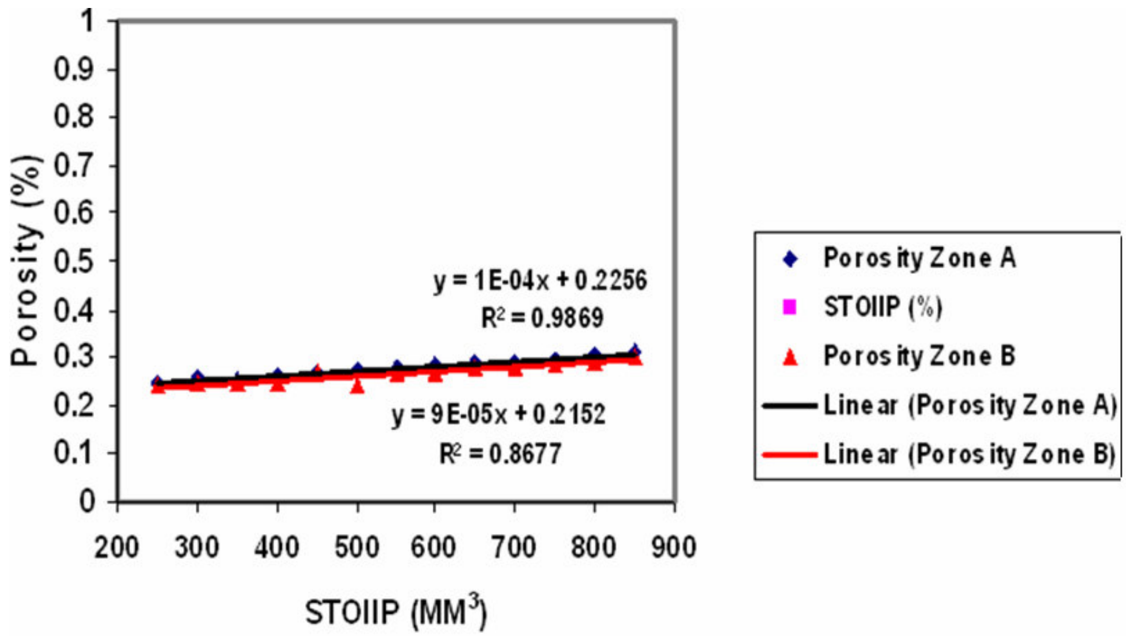

Figure 12. Graph showing the degree of dependence of STOIIP on porosity for geologic zone A and B.

and STOIIP, and porosity and STOIIP. The R^2 ranging between of 0.85 and 0.95 in the results of the regression analysis indicate a very strong positive dependence existing between N/G and STOIIP as well as between porosity and STOIIP. The observed positively N/G-STOIIP and porosity-STOIIP dependence showed that interval velocity of multi-layer modeling could be used in estimating volume of oil-in-place.

Geologic A encountered hydrocarbon in TMB1 well only with OWC at 2775 m both on log and on depth structure map of Geologic A. Geologic B on the other hand, encountered hydrocarbon in TMB 1, 4, 3 and 6 wells with OWC at about 2920 m both on log and depth structure map of the horizon. A crucial question in any inverse modeling for parameter determination is the reliability of end results. Based on the comparison of the geological structure modeling, the petrophysical parameters modeling, and calculations of volume according to different OWC, it showed that this interval velocity of multi-layer modeling could be used in estimating volume of oil-in-place. Given the simplicity of the model, this is a noteworthy result for it suggests that with better interval velocity estimate and improvements to the model, even more accurate determination of oil volume could be achieved.

Conclusions

This methodology, based on 2D modeling techniques, is particularly attractive because it can produce a model of layer cake type reservoirs that is fully consistent in 3D. Volumetric estimates is dependent upon thickness thus, interval velocity and petrophysical properties like porosity, hydrocarbon saturation and N/G. Volume estimates increase as the petrophysical parameters increase for each of the geologic zones. Estimating volume of oil using geological and petrophysical parameters ultimately depends upon the geologic input into the model, reservoir properties and the precision of the 2D mapping of reservoir geometry. This procedure makes it possible to correctly follow the risk evaluation throughout the development of an oil and gas field, thus making its management more efficient.

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