Available online www.jsaer.com

Journal of Scientific and Engineering Research, 2018, 5(1):1-10

Research Article

ISSN: 2394-2630
CODEN(USA): JSERBR

Evaluation of Reservoir Production Performance Using 3-D Seismic Mapping and Well Logs Analysis (A Case Study of Marginal Fields in Niger Delta, Nigeria)

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Abstract Hydrocarbon reservoirs delineation and their boundaries mapping using 3D seismic direct indicators and well logs data over " Extreme Field" offshore Niger Delta is presented to show the feasibility of integrating surface seismic and direct hydrocarbon indicators in mapping reservoir boundaries and also with well logs, to facilitate evaluation of hydrocarbon pore volume. The methodology involved horizon and fault interpretation to produce subsurface maps, amplitudes of reflection mapped to define lateral boundary and reservoir area extend determined using square grid template method. However, wire-line log signatures employed to identify hydrocarbon bearing sands and compute petro-physical parameters for hydrocarbon pore volume determination. Three hydrocarbon bearing reservoirs: R1, R2 and R3 delineated, porosity estimates varied from 0.22-0.31, hydrocarbon saturation: 0.6-0.9, thickness: (1.75-26.97) km^2 and reservoir area extent deduced from amplitude anomaly map: (9.79-1.88) km^2. Also, well–seismic tie revealed that reservoirs tied direct hydrocarbon indicators (bright and dim spots) on the seismic sections and structural maps revealed fault assisted closures at the center of the field which correspond to the crest of rollover anticlines and possibly served as the trapping mechanism. Estimates of oil and gas hydrocarbon-in-place revealed that R1 has the least hydrocarbon accumulation of 60,708.67 ft^3 of gas, R2 contained 43,407.70 barrels of oil and 123,019.78 $ft^3$of gas. However, R3 contained an estimate of 110,323.09 barrels of oil and 321664 ft^3 of gas respectively.

Keywords Reservoir, Delineation, Mapping, 3D Seismic, Well logs and Petro-Physical

Introduction

Reservoir development and production of hydrocarbon economic optimization involves having knowledge of reservoir hydrocarbon content, recoverability and recovery time. To achieve these set goals, there is a need to carryout geologic and geophysical studies that help engineers to understand the external geometry, internal architecture, flow contacts and barriers, aquiver size and lithology variation respectively. However, continuity of the reservoir in the areal as well as in the vertical direction and the reservoir extent and its closure are essentials. Also, location of the productive stratum and its boundaries, continuity of rock strata between adjacent wells, net pay thickness, saturation (oil, gas and water) and porosity of the reservoir rock are the essential information necessary for effective reservoir production performance evaluation

One of the costliest aspects of the oil industry operations is the cost of petroleum exploration. The cost of finding oil generally exceeds the cost of bringing it to surface. Exploration costs are expensive owing to the fact that petroleum is scattered in innumerable reservoirs and mostly, independently located. It requires the actual sinking of a well to prove the existence of oil and hence, produced it no matter how good the prospect may appear to be from the information gained through geology and geophysics. Today, fast and powerful computers and associated softwares are used to enable geophysicists' process and interpret the data so efficiently that demanding project deadlines are met within short time-frame. However, the subsurface picture provided by the

3D seismic survey has been proved, generally more precise and detail than any previously obtainable with 2D seismic. Consequently, 3D seismic has become an integral part of decision making for field appraisal and development for the evaluation of exploration acreage.

Moreover, in 1950's, approximately 50,000 wells were drilled annually, almost 40% were dry holes with one well in nine providing any production [1]. The vast sum of money sunk in dry holes constitutes a tremendous problem for the oil industry. Hence, one of the greatest technological developments to impact upon the oil industry generally and in particular the upstream part has been the introduction of 3D seismology and the gradual displacement of 2D seismology. The advances in 3D seismic imaging and increasing speed with which such images are made available to the explorationists thus, enables oil and gas to be found in "fairway" locations which might have been missed. Also, contributes to the enhancement of oil and gas recovery when allied with effective reservoir modeling techniques.

In literature, many articles summarizing the impacts of 3D seismic from various view, ranging from technical to economic have been published, Nestvold [2]. It was as early as 1970's when Walton [3] presented the concept of 3D seismic surveys and French [4] demonstrated clearly the value of 3D seismic over 2D seismic. Sheriff and Geldart [5] claim that the principle advantage of 3D over 2D is that 3D surveys result in clearer and more accurate pictures of geological detail and their costs are more than repaid by elimination of unnecessary development holes and by the increase in recoverable reserves through the discovery of isolated reservoir pools which otherwise might be missed.

West [6] research study concurs with Sheriff and Geldart [5] research finding. West claims that 3D seismic survey pays for itself many times over 2D in terms of reducing the number of development wells. It was further revealed that the extremely dense gridlines of 3D seismology makes it possible to develop a more accurate and complete structural and stratigraphic interpretation and thus, permitted locating producing wells not previously located on the basis of 2D seismic data. However, 3D surveying also helped define wildcat locations, helped prove additional outpost location, find additional reserves and undoubtedly provided data for more effective reservoir identification. In essence, the principle impact of 3D seismic on the upstream petroleum industry has been to reduce exploration and development cost of oil. The cost of exploring for oil and gas includes the cost of seismic surveying, geophysical modeling and exploratory drilling.

Hydrocarbon reservoirs delineation and their boundaries mapping using direct indicators from 3D seismic surveying for the purpose of quantifying producible hydrocarbon is an area which none among the notable researchers in this research development has never, until now considered. The knowledge of reservoir dimension is an important factor in quantifying producible hydrocarbon, Schlumberger [7]. Among the needed information includes the thickness and area extent of the reservoir. These parameters are important because they serve as veritable inputs for reservoir volumetric analysis i.e. the volume of hydrocarbon in place. It is therefore imperative that they are determined with reasonable precision. Precise determination of reservoir thickness is best obtained on well logs, especially using the gamma ray and resistivity logs [8]. However, almost all oil and gas produced today come from accumulations in the pore spaces of lithologies like sandstones, limestone or dolomites. Gamma ray log can come in handy to help in lithology identification i.e to differentiate between the reservoir rock (sand) and the embedding shale [8]. If core data is available, other lithologies like limestone or dolomites can be identified.

The resistivity log however, can be used for determining the nature of intersticial fluid i.e differentiating between (saline) water and hydrocarbon in the pore spaces of the reservoir rocks. Since these logs are recorded against depth, the hydrocarbon-bearing interval can be determined. Accurate mapping of the lateral dimension of the reservoir on the other hand, can be obtained from well logs, where abundantly available, or direct hydrocarbon indicators [9]. To use well logs to map the lateral dimension of the reservoir, the gas-oil and oil-water contacts are located on structure maps [10]. This process can be seriously hampered when limited borehole information from wells is available.

In this study, direct hydrocarbon indicators: bright spots, dim spots, flat spots and phase changes - on seismic sections in mapping reservoir area extent was utilized to determine reservoir characteristics. These indicators are valuable mapping tools because they suggest the presence of hydrocarbons directly on seismic sections (Brown, 2004). The Bright spot is a high amplitude reflection caused by the acoustic impedance contrast between the reservoir and the embedding medium (shale). In the hydrocarbon-bearing reservoir (e.g. gas sand), there is a lowering of the acoustic impedance due to hydrocarbon saturation compared to the embedding medium with high impedance. The dim spot is a decrease in amplitude of reflections over a short distance. The reflections appear dim' on the seismic sections. They are produced as a result of the contrast between the acoustic impedance of water sand, the embedding medium (shale) and that of the reservoir. The Flat spot is a horizontal reflection that is reflected from fluid to fluid interphases (fluid contact). Examples include gas–oil, gas-water, or oil-water contacts. The flat spot is easily identified by its flatness and un-conformability with adjacent reflections [11]. Phase change is the same as local wave-shape change. Reflections switch character across a fluid contact. This is as a result of significant change in acoustic properties between the gas sand above the hydrocarbon-water contact and the water sand beneath it [11].

Also, in mapping reservoir boundaries, studies of geologic structures that can hold hydrocarbon in place must be considered. Hydrocarbons are found in geologic traps or any combination of rock structure that will keep oil and gas from migrating either vertically or laterally [12]. These traps can either be structural, stratigraphic or a combination of both. Structural traps can serve to prevent both vertical and lateral migration of the connate fluid [10]. Stratigraphic traps include sand channels, pinchouts, unconformities and other truncations [13]. According to Doust and Omatsola [14], majority of the traps in the Niger delta are structural and to locate them, horizons are picked and faults mapped on seismic in-lines and cross-lines to produce the time structure map. This can reveal the structures that can serve as traps for the hydrocarbon accumulations. It is then possible to deduce the relevant petro-physical parameters from well logs, for the computation of the volume of hydrocarbon in place.

Applied Methodology

The data used in the study include digital suites of well logs, check-shot data, in-lines and cross-lines of 3-D seismic sections and base map of the study area. All were imported into the interactive Petrel 'workstation. The check-shot data was used for the well-to-seismic tie of the hydrocarbon reservoirs and displayed on the seismic lines they intersected. Horizons were tracked on these reflections, on both in-lines and cross-lines across the field to produce the time structure (isochron) maps. Also, the depth structure maps were produced from this, using velocity information derived from check-shot data. . The relevant wire-line log signatures were employed to identify hydrocarbon-bearing reservoirs and computing reservoir petro-physical parameters like porosity, water saturation, net reservoir thickness, gross reservoir thickness and the ratio of net to gross thickness. In addition, fluid contacts were delineated using logs which include: gamma ray log (lithology identification), volume of shale log (porosity correction), density and neutron log (delineating fluid contacts), resistivity and water saturation logs (identifying pore fluid type).

According to Brown [11], mapping the lateral boundary of the reservoir can be done (with the interactive workstation) by extracting and mapping amplitudes of direct hydrocarbon indicators like bright spots on the seismic sections. In this study, amplitudes of the horizons were extracted and presented in map form to produce reflection amplitude map. This was used to define the reservoir boundary. The surface area extent covered by the reservoir was estimated from this using the grid template method.

Results and Discussion

Reservoir Characteristics

Preliminary study on the well logs revealed three hydrocarbon-bearing reservoirs - R1, R2 and R3 - within depth interval of 8,000ft (2,440m) and 11,500ft (3,507m)shown in Figures 2 and 3. The salient reservoir petro-physical parameters obtained from these reservoirs are shown in Tables: 1, 2 and 3. It could be observed that hydrocarbon saturation and effective porosity estimates in reservoir R1 varied from 0.62-0.85 and 0.24-0.31.

The net thickness of the reservoir varied from 5.77ft (1.76m) to 71.24ft (21.73m). In reservoir R2, effective porosity varied between 0.26 and 0.24 while hydrocarbon saturation varied between 0.60 and 0.69. The net thickness of the reservoir varied between 20.56ft (6.27m) and 55.5ft (16.92m). For reservoir R3, effective porosity varied between 0.22 and 0.27 while hydrocarbon saturation varied between 0.65 and 0.93. The net thickness of the reservoir varied between 41.4ft (12.63m) and 88.4ft (26.96m). Well-to-seismic tie revealed that the hydrocarbon bearing reservoirs are associated with direct hydrocarbon indicators on seismic sections. Figure

4 is an example from reservoir R1. The top of reservoir R1 tied a dim spot at the two way travel time of 2465 m^2 i.e. depth of 9566ft (2917.63m).

Table 1: Computed Petro-physical Parameters from Reservoir R1

Well	Top(Md) Ft(m)	Bottom(Md) Ft(m)	Thickness (Gross) Ft(m)	Thickness (Net) Ft(m)	Net/Gross	Porosity (Effective)	Hydrocarbon Saturation
01	9,517(2,902)	9,600(2,928)	25(7.63)	25(7.63)	0.75	0.24	0.62
04	9,566(2,917)	9,577(2,920)	25(7.63)	25(7.63)	0.56	0.31	0.85

Table 2: Computed Petro-physical Parameters from Reservoir R2

Well	Top(Md) Ft(m)	Bottom(Md) Ft(m)	Thickness (Gross) Ft(m)	Thickness (Net) Ft(m)	Net/Gross	Porosity (Effective)	Hydrocarbon Saturation
01	10,541(3,215)	10,590(3,229)	70.10(21.38)	55.50(16.93)	0.78	0.24	0.69
04	10,550(3,217)	10,594(3,231)	44.00(13.42)	20.56(6.27)	0.39	0.26	0.60

Table 3: Computed Petro-physical Parameters from Reservoir R3

Well	Top(Md) Ft(m)	Bottom(Md) Ft(m)	Thickness (Gross) Ft(m)	Thickness (Net) Ft(m)	Net/Gross	Porosity (Effective)	Hydrocarbon Saturation
01	11,151(3,401)	11,249(3,430)	98.40(30.01)	74.10(22.60)	0.75	0.25	0.85
03	10,898(3,323)	11,021(3,361)	123.83(37.76)	88.4(26.92)	0.71	0.25	0.65
04	11,125(3,393)	11,197(3,415)	72.23(22.03)	41.4(12.63)	0.57	0.22	0.93
05	11,022(3,361)	11,117(3,390)	95.82(30.05)	54.3(16.56)	0.56	0.27	0.90

Since the bright and dim spots are indicative of hydrocarbon presence, the lateral boundaries of these reservoirs were mapped from the amplitudes. In the research, horizon picking were initiated on the bright spot and dim spots reflections. Their amplitudes were extracted and presented in map form as shown in Figure 5. Reservoir R1 is seen as an anomalous low amplitude zone on the map in the center of the field and correlated with the gas-bearing reservoir as revealed on neutron-density overlay, from well 4 in Figure 2. The total estimated area covered by the gas sand was 9.79 Km^2. The same analysis was performed for reservoirs R2 and R3; that is, reflection amplitude maps were generated for horizon two and three respectively and the zone of anomalous high amplitudes were used to map the boundaries of the reservoir (They matched bright spots on seismic sections). The reservoir area extent estimation from the square grid method revealed that reservoir R2 covered an area of 10.56Km^2 while reservoir R3 covered an area extent of 11.88Km^2.

Horizon and fault interpretation were carried out for subsurface structural interpretation. In all, three horizons (One, Two and Three) and five faults – F1 through F5 - were mapped on seismic sections over the entire field, (Figure 6). Figures 7 and 8 are respectively the time and depth structure maps generated from 3-D structural interpretation. The principal structure responsible for hydrocarbon entrapment in the field is a structural high located at the center of the field which probably corresponded to the crest of the roll over structure observed on the seismic sections, Figure 6. This was observed as fault assisted closures on the time structure maps of each horizon. Figure 7 is the time structural map of horizon one. Structural highs are observed in the northeast and in the center of the field while structural lows are observed in the southwest. Using the information on this map, the crest of the roll over structure (structural high), antithetic fault F2 and growth fault F3 act as good traps for the hydrocarbon accumulations in reservoir R1 at the center of the field. The other faults identified on the map include F1 (a growth fault), F4 and F5 (minor faults), and fault F2, which is an antithetic fault.

Hydrocarbon-in-Place

The depth structure map generated revealed that for horizon one, the depth to the top of hydrocarbon ranges between 9,500ft (2,897.5m) and 9,566ft (2,917.63m), Figure 8. Similarly, for horizon two (not shown), the depth to the top of hydrocarbon ranged between 10,500ft (3,202.5m) and 10,700ft (3,233m) at the center of the field while for horizon three, depth to the top of hydrocarbon at the center of the field varies between 11,000ft (3,355m) and 11,200ft (3,401m). Hydrocarbon pore volume estimates showed that Reservoir R1 has a volume of 60708.67 cubic feet of gas; reservoir R2 has oil in place of 43,407.70 barrels and gas in place of about 123,019.78 cubic feet while Reservoir R3 has the highest hydrocarbon accumulation with a total estimate of 110,323.09 barrrels of oil and 321,664.36 cubic feet of gas. The detailed analysis is shown in Tables 3 and 4.

Table 4: Oil Volume Estimates in Reservoirs R1 and R2

Reservoir	**Porosity**	**Hydrocarbon Saturation**	**Thickness (Oil) Ft(m)**	**Net/Gross**	**Area m^2**	**Hydrocarbon Oil-in-place (Barrels)**
R2	0.25	0.65	15.00(4.57)	0.88	10560	43,407.70
R3	0.26	0.80	30.00(9.10)	0.78	11880	110,323.09

Table 5: Oil Volume Estimates in Reservoirs R1, R2 and R3

Reservoir	**Porosity**	**Hydrocarbon Saturation**	**Reservoir Thickness Ft(m)**	**Net/Gross**	**Area $Km^2(ft^2)$**	**Gas-in-place ft^3**
R1	0.26	0.80	52.90(16.13)	0.75	9.79(32,120.99)	60,708.67
R2	0.25	0.65	23.00(7.02)	0.95	10.56(34,647.36	123,019.78
R3	0.28	0.27	25.00(7.63)	1.00	11.88(38,978.28)	321,664.36

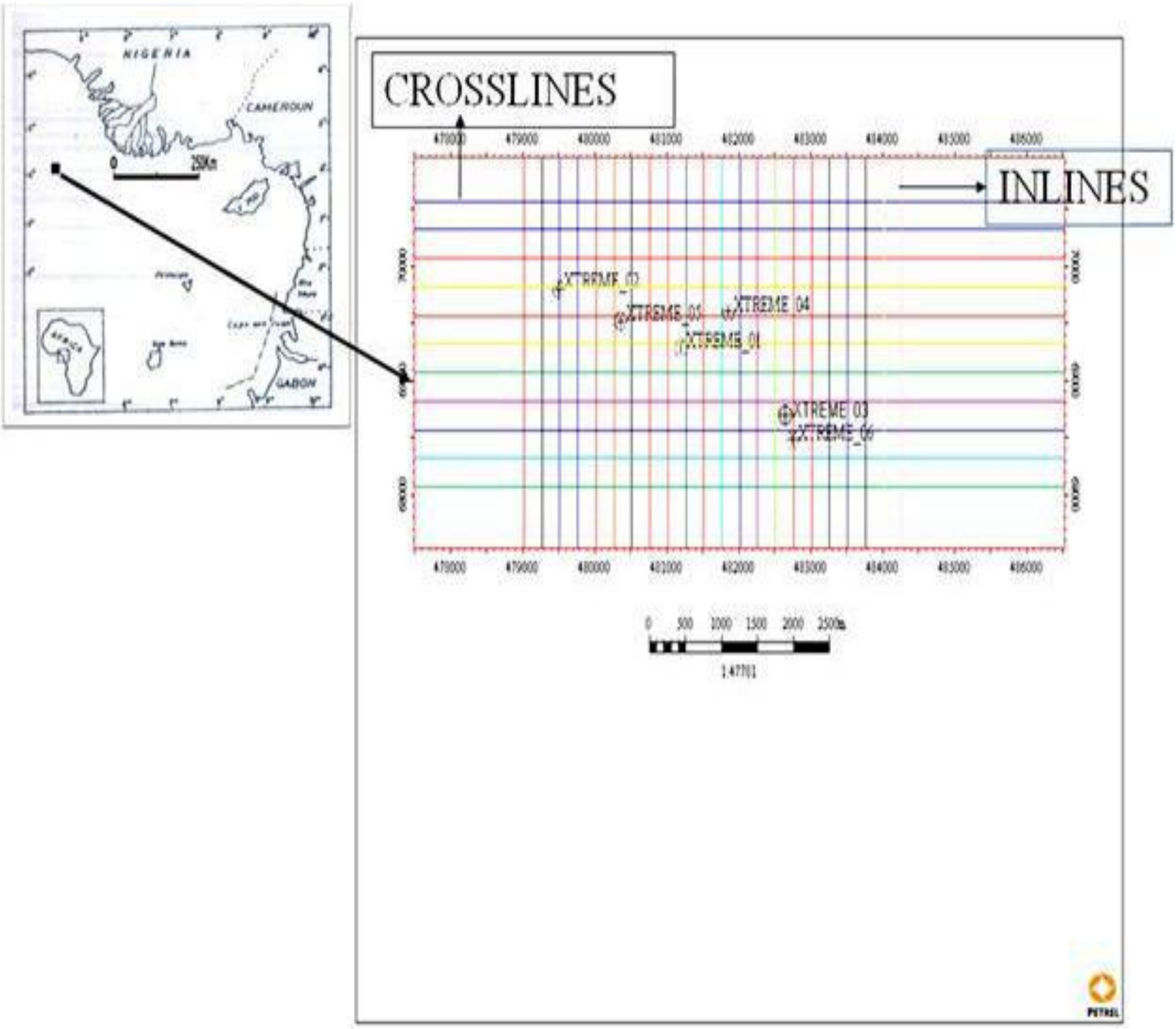

Figure 1: Location and Base Maps of the Area showing Seismic Lines and Well Logs

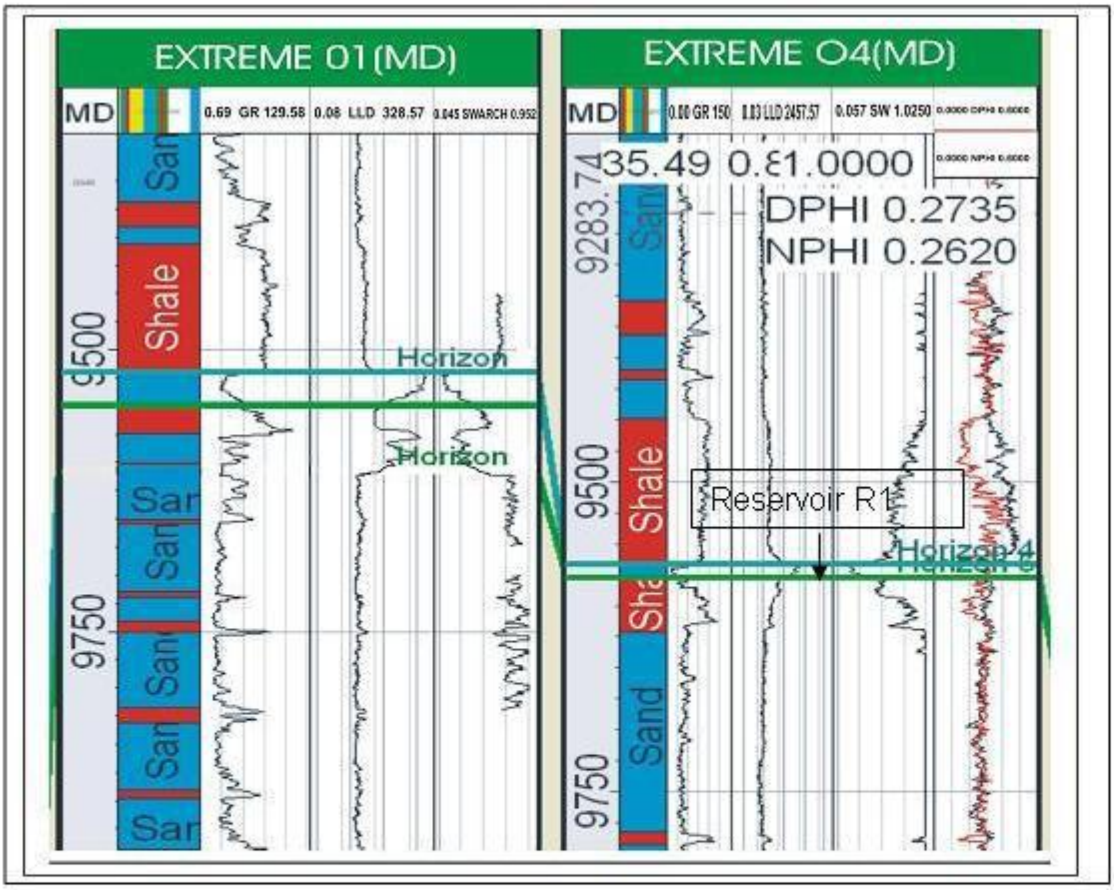

Figure 2: Reservoir R1 Delineated on the Well Logs

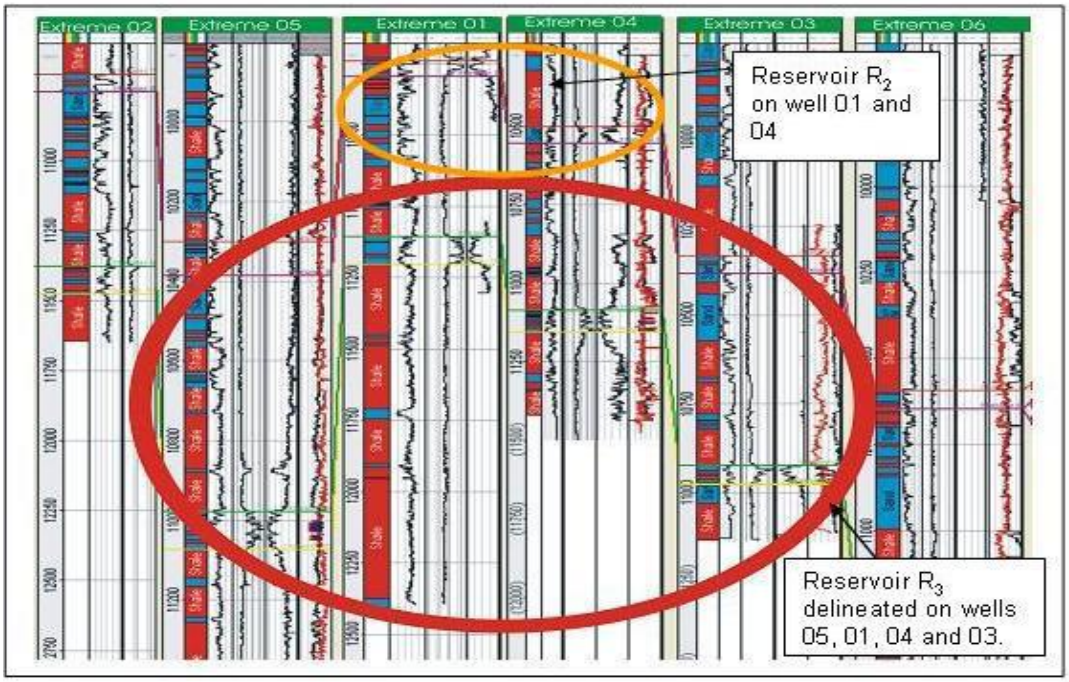

Figure 3: Well sections showing Reservoirs R2 and R3 delineated on well Logs

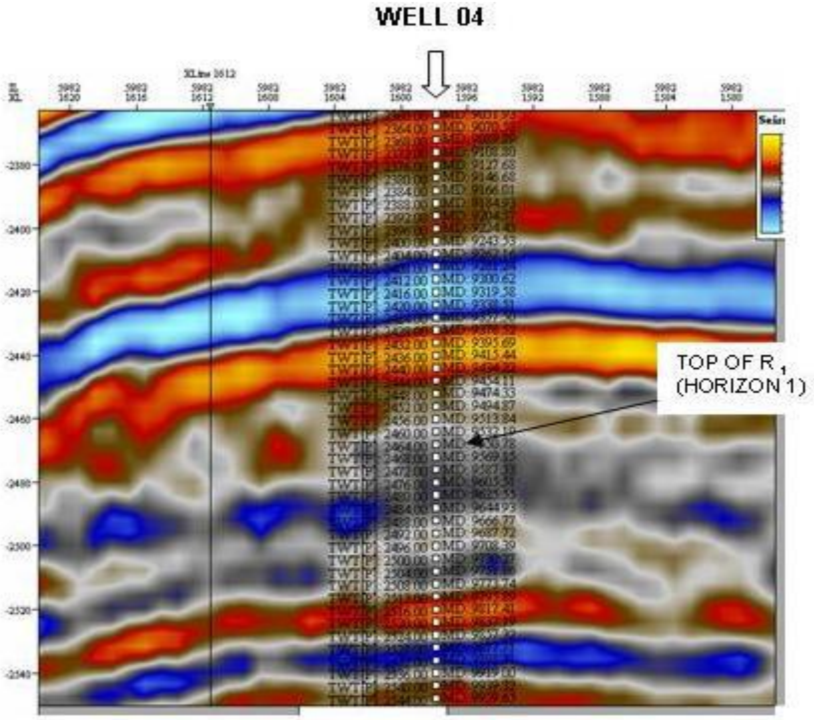

Figure 4: Well-to-seismic tie of reservoir R1 from well 04 (showing dim spots)

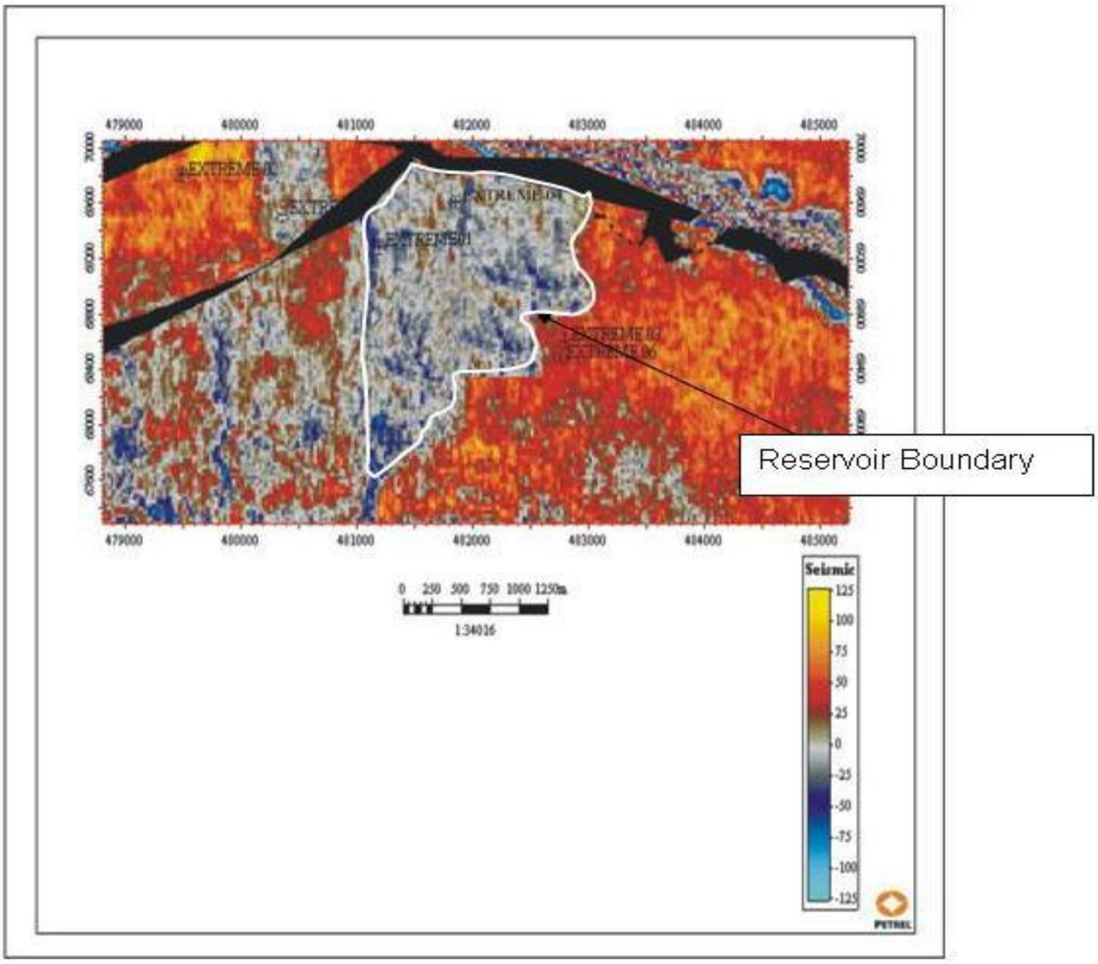

Figure 5: Reflection Amplitude Map of Horizon one delineating the Lateral boundary of Reservoir R1

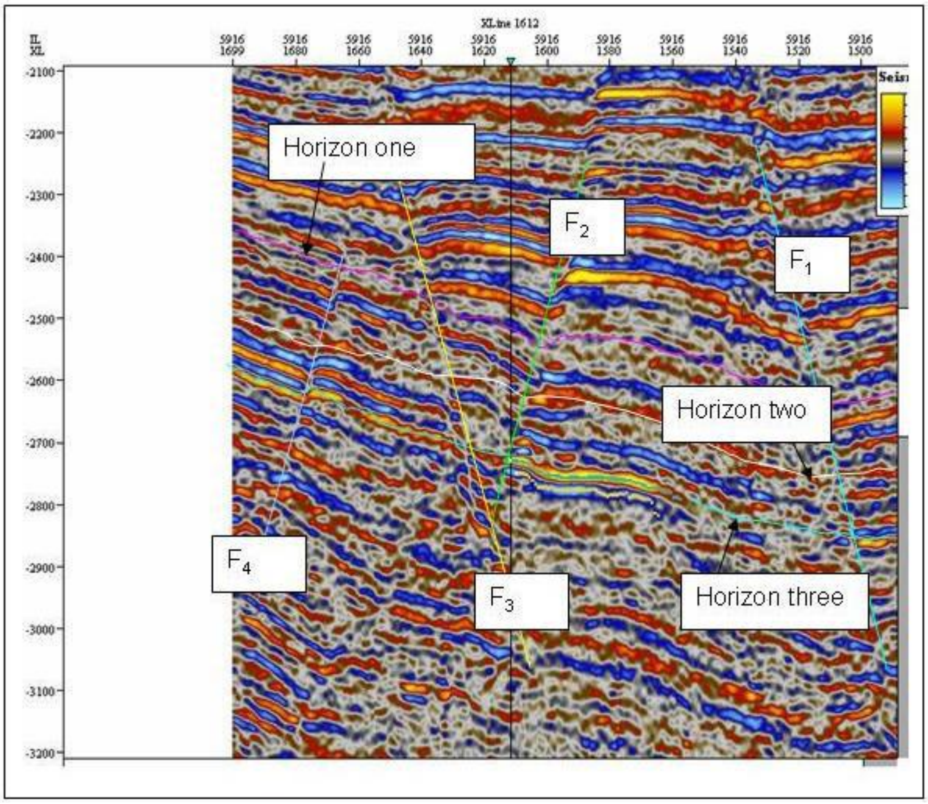

Figure 6: Typical seismic section (Inline 1699), showing Horizons and Faults

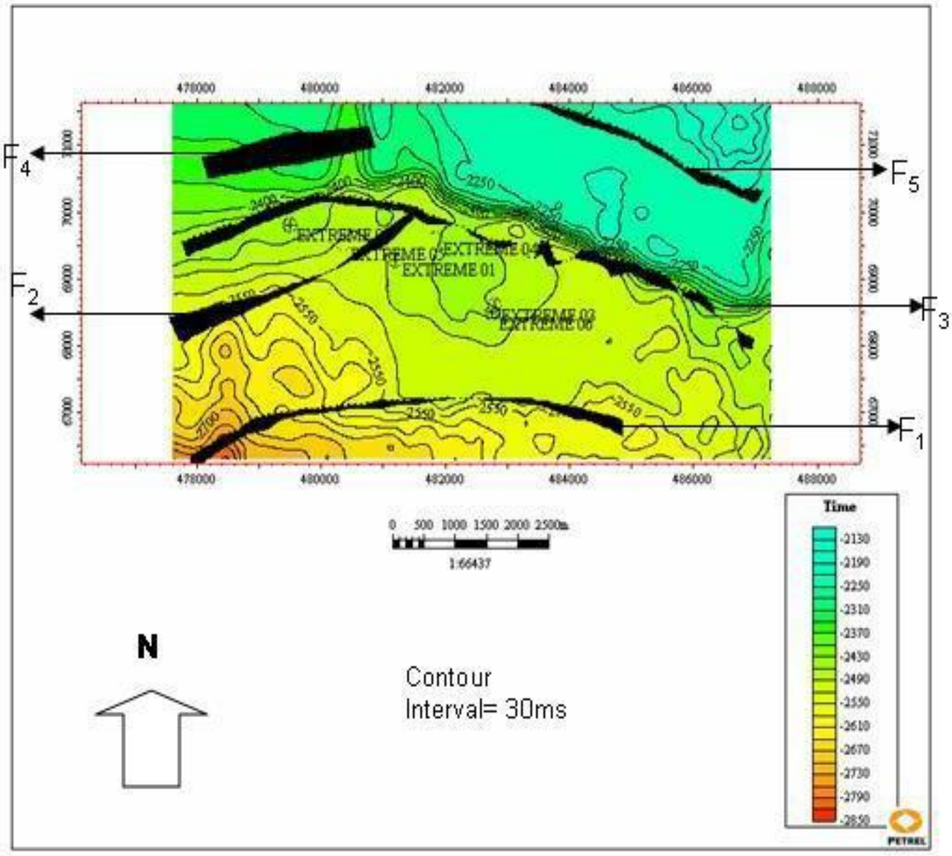

Figure 7: Time structural map of Horizon one

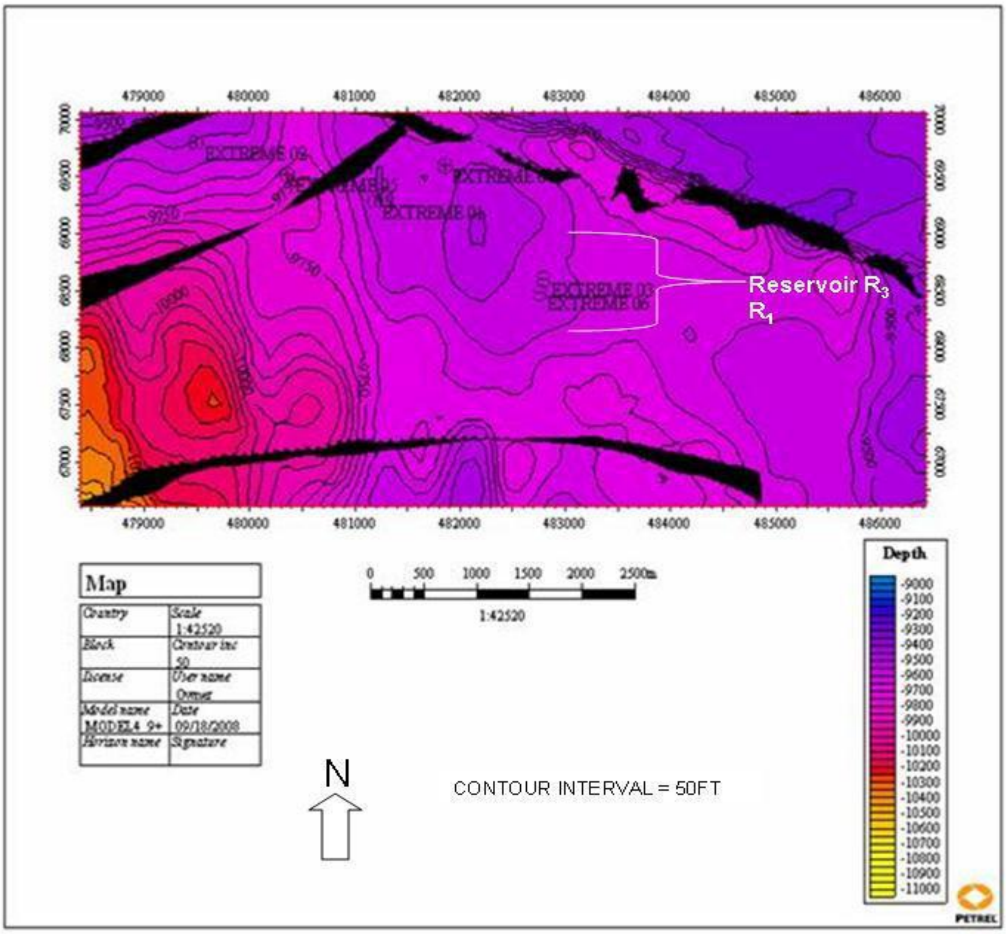

Figure 8: Depth Structure Map of Horizon One

Conclusions

Delineation and mapping of hydrocarbon- bearing reservoir boundaries from surface seismic sections and well logs analysis within the depth interval of 8,000ft (2,440m) and 11,500ft (3,507m) has shown the feasibility of integrating surface seismic and direct hydrocarbon indicators in mapping reservoir boundaries and also, evaluation of hydrocarbon-in-place. Hence, implementing all the considerations and executing as per procedure can attain the following benefits to the oil industry:

- Hydrocarbon –producing reservoirs identification.
- 3-D structural interpretation and estimation of oil and gas hydrocarbon-in-place in the reservoirs.
- Revealing hydrocarbon bearing reservoirs relationship with direct hydrocarbon indicators (Bright spots and dim spots) to facilitate horizons and faults mapping for 3-D subsurface structural interpretation.
- Generating structure map for the identification of principal structures responsible for hydrocarbon entrapment in the field.

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