Egyptian Geophysical Society
EGS Journal, Vol. 14, No. 1, 29-40 (2016)

DELINEATION AND EVALUATION OF PLIOCENE CHANNEL COMPLEX, WEST NILE DELTA, EGYPT

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تمييز الصخور وحساب خاصية حجم الغاز باستخدام تحليل الشبكة العصبية

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الخلاصــة: قنوات الرمال المنحدرة المتواجدة فى المناطق المتعددة حول العالم تعتبر حالياً واحدة من أهم خزانات البترول. و معرفة شكل هذه القنوات وإمتدادها وما تحتويه من وحدات رملية أصغر و كذلك فهم خصائصها يعتبر مهماً جداً للحصول على الإنتاج الأمثل للبترول من هذه الخزانات وهذا هو هدف هذه الدراسة.

ABSTRACT: *Slope channels are regarded currently as one of the most important reservoirs in several localities around the world as Gulf of Mexico (USA), Offshore West Africa, Offshore Indonesia, Offshore Nile Delta (Egypt), etc. Most of these slope channels reservoirs mainly belong to Cenozoic epoch. Within the Nile Delta gas province, reservoirs are dominated by Pliocene slope channel systems and understanding the geometry and distribution of its component sand bodies is very important. It is argued that when deepwater reservoir architecture is understood, this can be used to improve deepwater reservoir production performance.*

The objectives of the current study are to predict sand distribution and reservoir presence and the main targets are to follow the Pliocene channel prospect and evaluate its characteristic. Accurate petrophysical evaluation of deep water channels composed of thin bedded sand-shale sequences is crucial in the economic decision to explore, develop and produce these reservoirs.

Visualization of the geometry of the Pliocene channel complex is based on 3D multiazimuth (MAZ) seismic data. The high resolution seismic, combined with log observations, provide spectacular insights into the gross seismic architecture and the internal geometry of the Pliocene channel complex.

In the studied area, the Pliocene channel structure is complex in terms of faults distribution with more faults in the southern half of the structure. It consists of multi-sand package in the northern part of the channel with high net to gross (NTG) while the southern part of the channel exhibits only one sand package has low net to gross (NTG).

INTRODUCTION

The Nile Delta has attracted significant subsurface interest in recent years because it is a prolific gas province with several multitrillion cubic feet discoveries (Samuel et al., 2003; Abdel Aal et al., 2006 and Taylor et al., 2009). This resource has more than doubled in the last few years, largely from successful deep water exploration for Pliocene slope-channel systems (Dolson et al., 2005). Channels are defined as elongate negative relief feature produced and/or maintained by turbidity flow. Channels represent relatively long-term pathways for sediment transport. Channel shape and position within a turbidite system are controlled by depositional processes or erosion down cutting (Mutti and Normark, 1991). Channel shape varies, from elongate, relatively straight channels to those that are highly sinuous, general observations are that the degree of sinuosity is inversely proportional to slope gradient, and that finer-grained, lower-energy channel fills tend to be more sinuous than do coarser-grained, higher-energy fills. The hierarchy, scales, stacking patterns and naming conventions used in the description of the study area are based on the hierarchy of Sprague et al, (2002): • Channel complex set: ~1.5 -2.5 km wide and ~ 150-190m thick. • Channel complex: <1km wide and ~50m thick. • Channel element: ~250m wide and 10-15m thick. • Leveed channel: ~250m wide, 10-15m thick and possessing asymmetric levees up to 1km wide. The main target in this study is to define the pattern of the channel complex set only and to evaluate the reservoir zones inside it. The study area is a field located in the North Alexandra B concession, 50 km offshore, on the western flank of the Nile Delta down slope (northwest) of the mouth of the Rosetta Branch of the Nile River (Figure 1). It lies in a water depth varies from 80 m to 1010 m. The concession comprises a stacked sequence of slope channel-levee, lobe and channel complex reservoir systems of mid Plioceneage.

Geological setting:

The Nile Delta lies on the northern margin of the African plate and has evolved through multiple rift episodes in the Triassic-Early Cretaceous, through a short lived passive margin phase in the Cretaceous, and into an active compressional margin since the Late Cretaceous. Today, the Nile Delta is surrounded by active compressional belts which have important implications for the types of structures that develop across the Nile Delta.

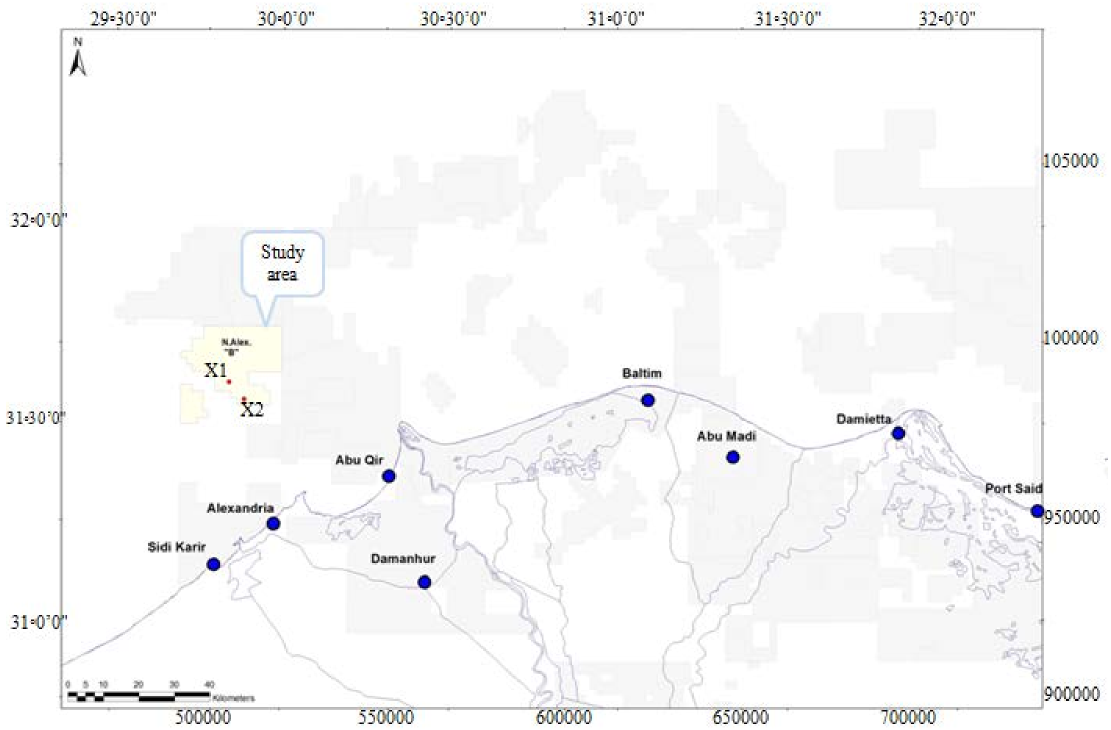

Figure (1): Location map of the studied area.

The development of the Pliocene slope systems in the west Nile Delta is largely controlled by both the Coastal (E-W) and Rosetta (NE-SW) fault systems (Figure 2). Extensional movement on these faults is also considered responsible for the generation of the northeast-southwest oriented west Nile (Raven-Taurus) anticline that sets up the structural trapping component of many of the fields in this area (Butterworth and Verhaeghe, 2013). During the early Tertiary, there was a major clastic influx from the proto-Nile system and the development of multiple feeder systems that developed offshore into slope turbidite channels and more distal basin-floor fans. During the late Miocene, a regional Mediterranean low stand event resulted in the Messinian salinity crisis and widespread deposition of evaporite deposits and the development of deeply entrenched incised valleys. After the Messinian salinity crisis, the Plio-Pleistocene represented a return to deep marine conditions. Thick deposits of Kafr El Sheikh marine shales preceded the progradation of the present day Nile Delta and the offshore turbidite sands that traversed the slope. These deposits manifest themselves as a series of compensationally stacked channel-levee, lobe, and channel complex sets within a progradational mud-dominated slope. The deeper seated Raven-Taurus anticline has grown episodically throughout Pliocene times, and the northwesterly draping turbidite channels that cross these structures form the three-way components to the trap. The combination of subtle structural growth, and regular, episodic slope collapse at a variety of different scales, are instrumental in controlling the slope position and internal fill of stacked Pliocene gas reservoirs (Figure 2).

Delineation of the pliocene channel complex:

3D seismic offers more scope for defining the external geometry and internal architecture of reservoir bodies. The detailed map view derived from 3D seismic is often more instructive than the individual section do (Bacon et al., 2003). The main objectives of 3D seismic interpretation in this study are to delineate the external geometry of the Pliocene channel complex (top and base of the channel) and trace the faults trends affecting on it. The study area was covered by different azimuth seismic data (30, 90 and 150 degree). These individual seismic volumes have been processed to develop multi-azimuth (MAZ) volume. The resulting seismic image provided much improved temporal and spatial resolution, having a seismic bandwidth of up to 90 Hz at reservoir level. Based on the tuning calculation, the seismic data appeared to have a resolving power of 11.5m (equivalent to channel element) at Pliocene/reservoir level. The seismic data is of SEG normal polarity. Seismic interpretation was carried out using a workstation with Landmark® 3D Seismic Interpretation Software.

3D Seismic interpretation:

A detailed 3D seismic interpretation of key seismic horizons was started by seismic-to-well ties to ground-truth (tie) the seismic horizons to geological markers at the wells, Seismic-to-well ties were undertaken on a well-by-well basis. The steps of 3D seismic interpretation are started by well to seismic tie followed by horizon picking and fault interpretation.

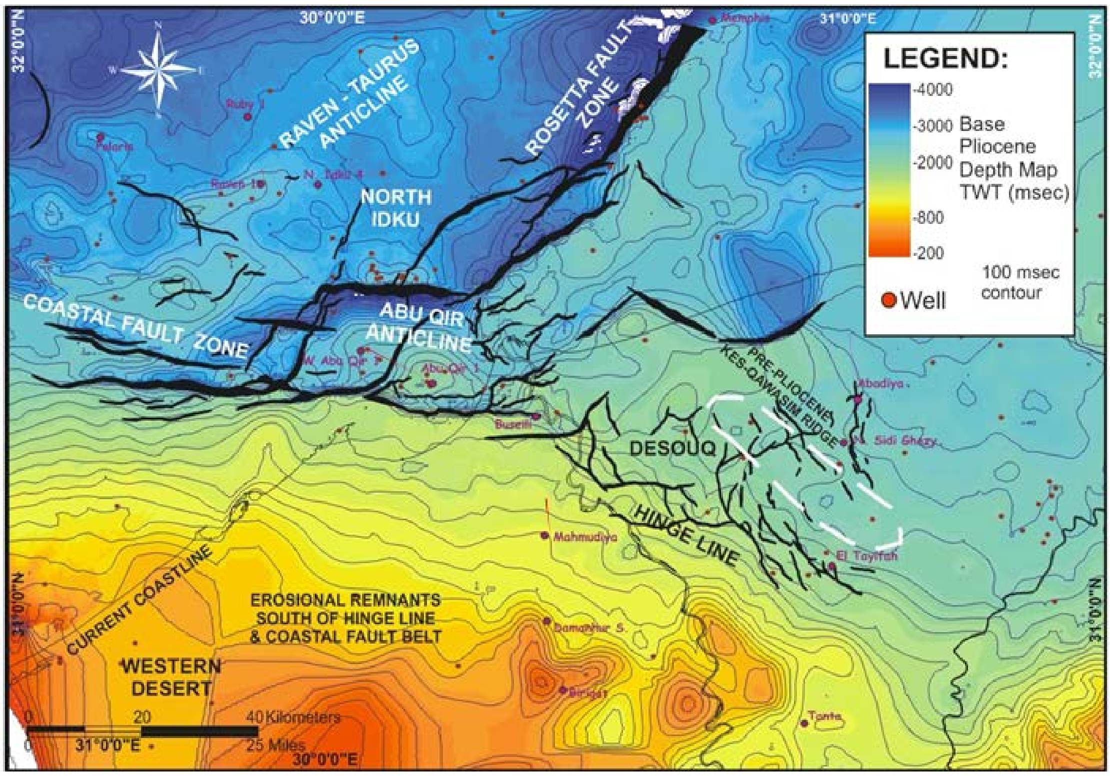

Figure (2): Structural features of the west Nile Delta (after Kellneret al., 2009)

Seismic to well tie:

Geological and geophysical interpretation involves the creation of earth models whose response describes observed data from geophysical recordings, well logs and cores. The most widely used application of synthetic seismograms in exploration seismology is in the computation of reflection coefficients from well logs in order to tie log information to the picking of reflection events on seismograms. If waves encounter a discontinuity in the acoustic impedance (product of rock density and seismic velocity), the result is a reflected wave. The ratio of the reflection amplitude to the incident wave amplitude is given by the reflection coefficient (as described in Robinson and Treitel, 1980).The first step in making a perfect well-tie is to run pilot analyses to establish the parameters for estimating the wavelet, key among which is can of time gates and traces around the well for the best match location (Roy (1997) and Roy and Tianyue (1998)). Scanning is done to establish the best-fit location which may be slightly away from the well location and within a certain time window. At this point, we need an initial wavelet to generate synthetic data to be compared with actual seismic data so that we can come up with the actual seismic trace in the vicinity of the well and the time range(s) to use in the final well tie. In order to get the correct phase of the wavelet, we would prefer to use the well logs. Because well log correlation is not yet done, mis-tie between log and seismic data would make that extracted wavelet unacceptable (Hampson-Russell (2011)). Using the usually noise-free, default 'Ricker' wavelet is not a good idea. This presents a challenging riddle in that to extract a wavelet through logs, you must have an optimum correlation, and yet to correlate properly, you must know the wavelet. Hampson-Russell (2011) proposes the following "practical" steps. **1)** Determine the approximate phase of the wavelet or assume some constant phase. **2)** Extract the wavelet statistically from the seismic. **3)** Correlate the logs to the seismic data. **4)** Run a Seismic-Well scanning algorithm to establish the best match location. **5)** Apply the phase rotation for the cube (130 degree). **6)** Re-extract a new wavelet using the correlated well logs from the rotated cube. 7. Check the re-extracted wavelet (a zero-phasing wavelet) to get the best match between the synthetic and real seismic data. As the program allows, enter time-depth pairs from a survey and stretch or squeeze the synthetic to fit (this should give a fairly close match to the real data); pay attention to the datums of the synthetic and the seismic. Figure (3) represents amplitude and frequency spectra of the statistically extracted wavelet and the synthetic seismogram for X2 Well

Horizon picking and fault interpretation:

Horizons were interpreted based on seismic events observed in the seismic-well ties as geological markers that were defined as follows: a- Top channel/reservoir sands mostly defined by a soft kick, i.e. a reduction in Acoustic Impedance (AI) as the seismic rays cross the interface between the overlying shales (with larger values of AI) and the gas-bearing sands (with smaller

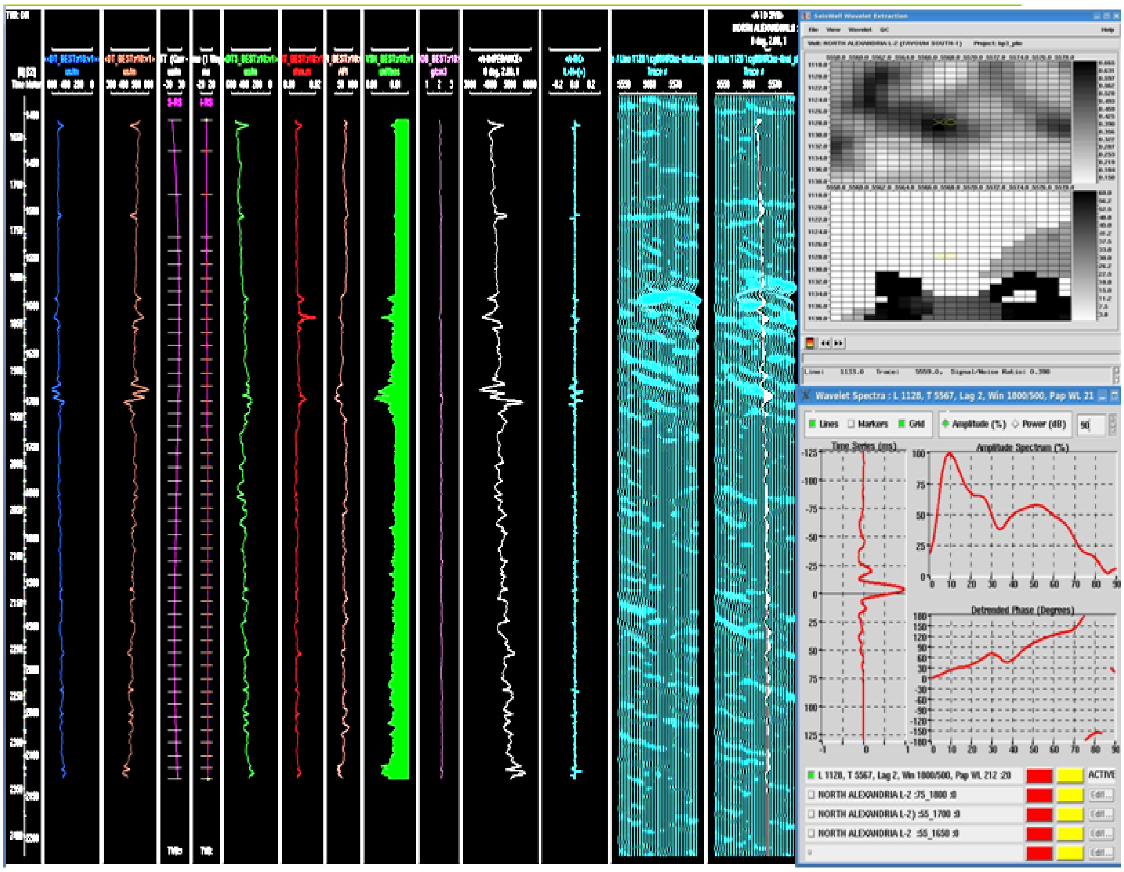

Figure (3): Right: the amplitude and frequency spectra of the statistically re-extracted wavelet (zero-phasing). Left: the synthetic traces (white) were computed using by convolution of the statistical re-extracted wavelet with the computed reflectivity series. This represents the best match between the synthetic trace and real data for X2 Well.

values of AI). This event mostly represents the top of the gas-bearing sand unit i.e. the top Channel geological marker. b-The Base Channel or Base Brine Sand often defined as a hard kick or a composite (with the Base Gas event) hard kick. There is generally more uncertainty as there is much less of an impedance contrast between the brine sands and the shale, and also because of the generally thinner brine sand units (often at or below the level of seismic visibility). Due to the aforementioned challenges, this horizon has been interpreted as channel incision i.e. cut downward in the preexisting substrate. c- Faults The fault patterns have been interpreted and marked on the seismic sections. The identification of faulting on seismic sections, according to Dobrin (1976), is based on principle indications; discontinuities in reflection falling along an essentially linear pattern, disclosures in tying reflections around loops, divergence in dip not related to stratigraphy, diffraction patterns and distortion or disappearance of reflections below suspected fault lines. Also, time slices are used for imaging discontinuities. They are more suitable for detecting and following faults laterally.

Interpretation tool:

Geologic interpretation of seismic data may be simple if there is adequate well control, but in many cases the interpreter has to make inferences from appearance of observed bodies. This may include both their external form and, if the resolution is good enough for it to be visible, the geometry of internal reflections. Some ways of looking for distinctive features are as follow (Bacon et al., 2003): 1) Vertical section, it is adequate to show the geometry of individual bodies, particularly if they thick enough to show distinctive internal reflections. The interpreted seismic sections provided information on the configuration of the mapped horizons (top and base of the channel) and the structural geometry through a certain direction. The seismic section only allows looking at a 2D profile of the earth. Thus, the information obtained from a series of seismic sections gives a general idea of the geological structure in this case the channel. Figures (4 and 5) show horizons picking (top and base of the channel complex) and fault interpretation respectively. 2) Horizontal sections, time slices can reveal map-view geometry such as channel system. However, if there is structural dip present, the horizontal slice does not show data referring to a single stratigraphic level. Thus, different structural types, trends, areal extension and vertical relief can be viewed in the horizontal plane through the whole area. Figures (6) and (7) represent the time slices that reveal the channel geometry and the faults effect on it respectively.

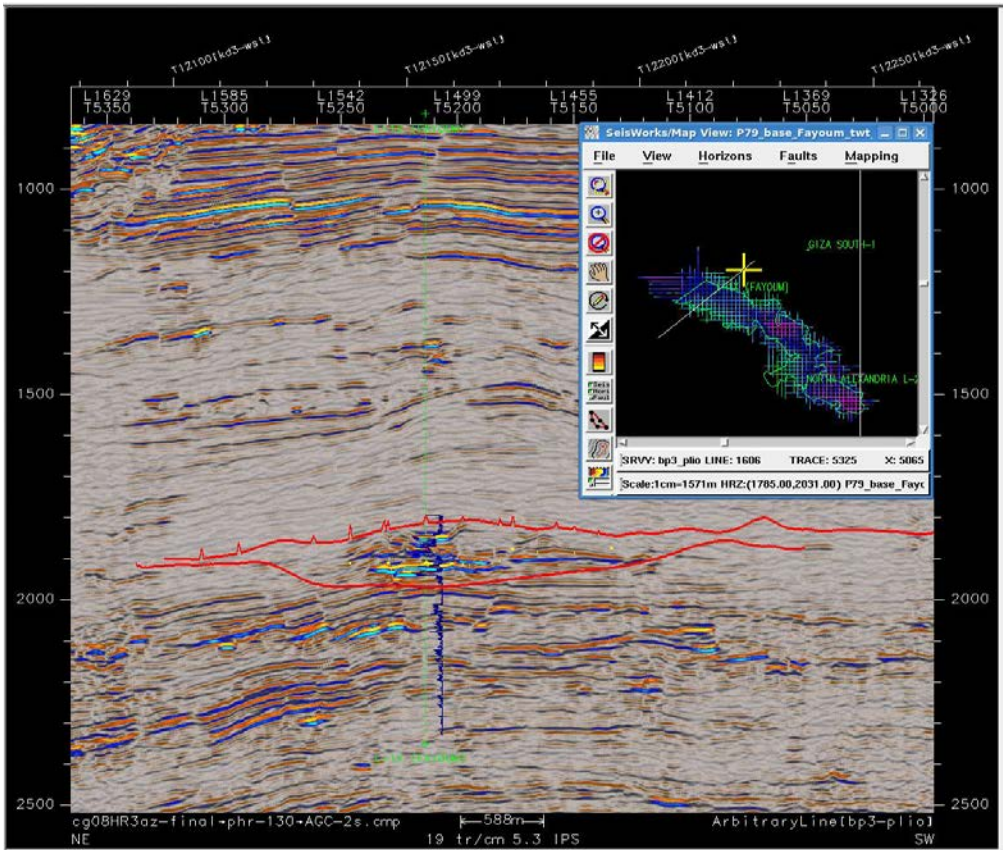

Figure (4): Arbitrary seismic section (trending NE-SW) represents top and base of the channel correlated with GR log

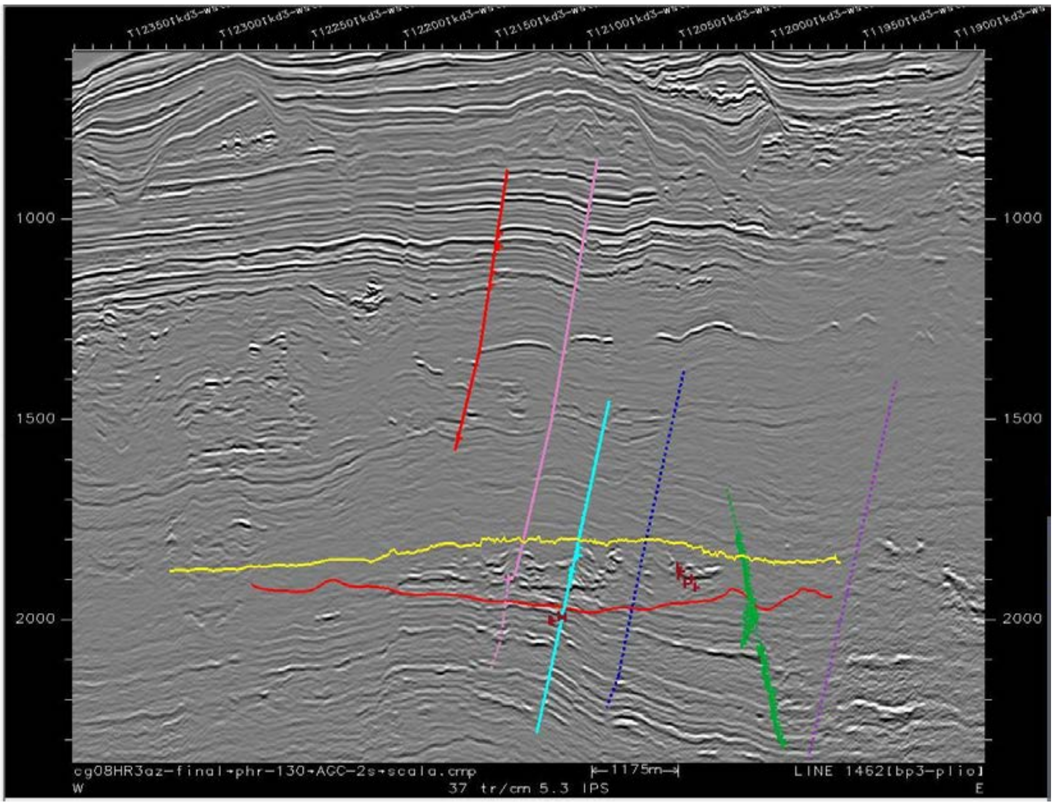

Figure (5): Inline seismic section trending W-E shows top (yellow), base (red) and fault interpretation of the channel.

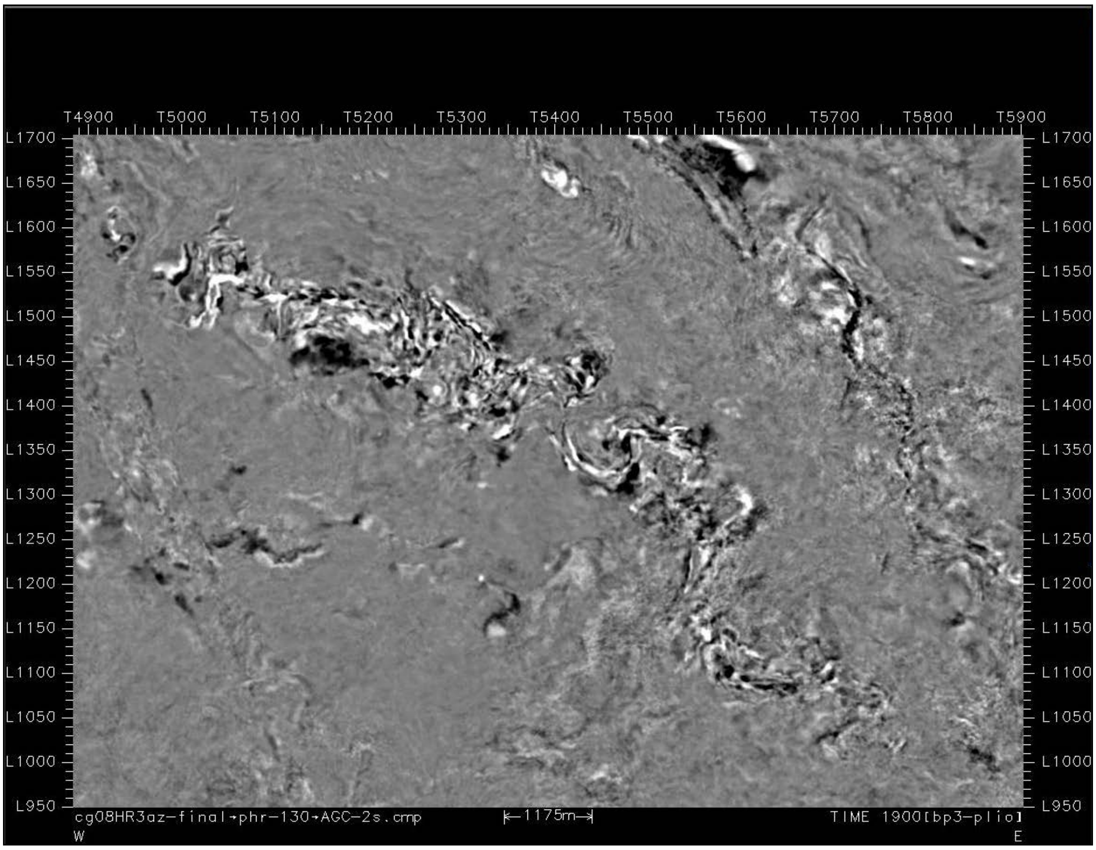

Figure (6): Reflectivity time slice at 1900 msec represents the best display of the Pliocene channel complex.

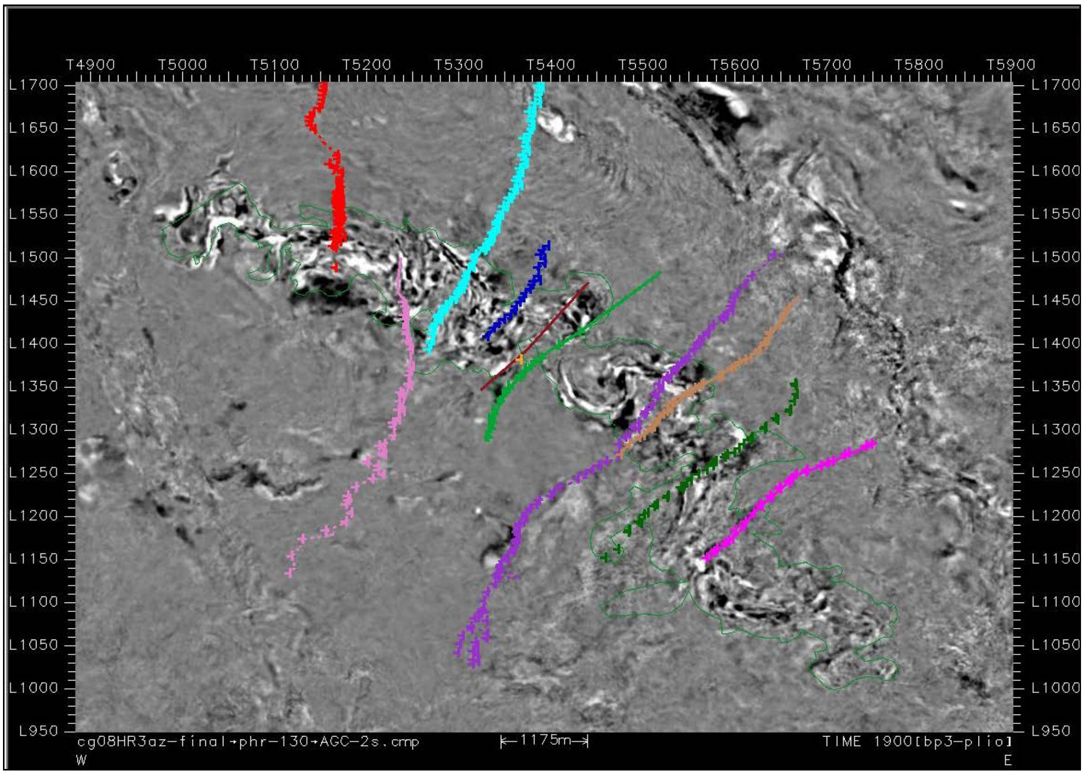

Figure (7): Reflectivity time slice at 1900 msec represents the best display of the Pliocene channel and the faults through it.

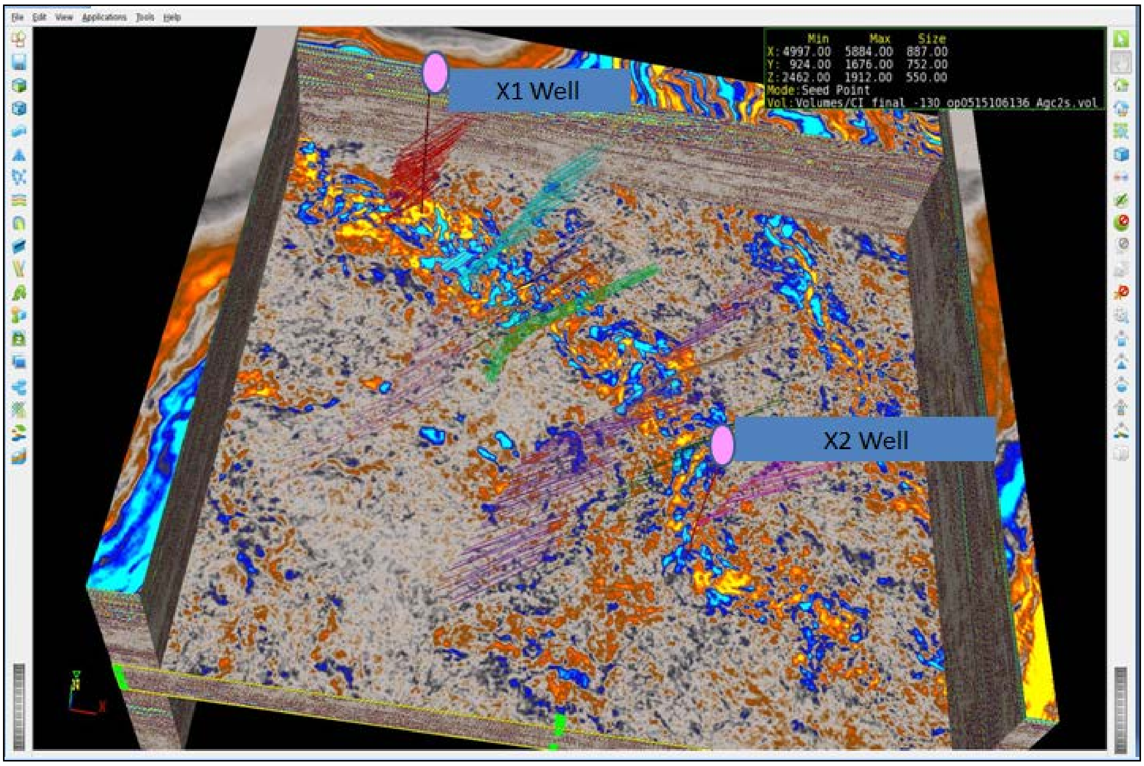

Figure (8): 3D visualization of the Pliocene channel complex through the survey area by using Geoprobe software.

3) 3-D views, this type of view can be very helpful in understanding a geologic feature. The traditional method of working has been to make different 2D sections through the 3D volume, as inlines, crosslines, random tracks or time slices. Today, it is possible to view entire datasets so that the interpreter can quickly get a feel for the actual 3D nature of the trap. To do that a simple technique is to use interpreted horizons to guide sculpting; for example, data might be removed above and below a reservoir so as to leave a 3D body corresponding to the reservoir alone as shown in Figure (8).

Pliocene channel complex pattern:

The Pliocene channel trap is a 15 Km long, NW-SE curve shaped turbidite channel that is draping over a structural high trending NW-SE. The reservoir distribution and segmentation is highly controlled by faults. Most of these faults (trending NE-SW, Rosetta Fault systems) exploit the planes of weakness in the channel (channel bends). The Pliocene channel system is subdivided into three main segments with different sand distribution. 1-Segment 1 was penetrated by X1 Well. It is composed of a thick sand package of a multi-story stacked channel with different frequencies of the amalgamation surfaces between the channels. This facies is interbedded with a few meters of thin bedded facies. 2-Segment 2 sand distributions is highly controlled by faults, and most channels tend to aggrade vertically against the faults. The channel in this segment shows a laterally accretionary pattern. 3-Segment 3 is the main appraisal target for the X2 Well. The sand distribution of this segment is slightly different from Segment 1 and Segment 2. X2 well will be drilled within the confined system as X1 but the sands at X2 are expected to have less amalgamated nature. Two main sand bodies can be identified as separated by a possible discrete shale package in between.

Evaluation of Pliocene channel complex:

The goals of formation evaluation can be summarized by a statement of four questions of primary interest in the production of hydrocarbons (Ellis and Singer, 2007): 1) Are there any hydrocarbons, and if so are they oil or gas? First, it is necessary to identify or infer the presence of hydrocarbons in formations traversed by the well bore. 2) Where are the hydrocarbons? The depth of formations which contain accumulations of hydrocarbons must be identified. 3) How much hydrocarbon is contained in the formation? An initial approach is to quantify the fractional volume available for hydrocarbon in the formation. This quantity, porosity, is of utmost importance. A second aspect is to quantify the hydrocarbon fraction of the fluids within the rock matrix. The third concerns the areal extent of the bed, or geological body, which contains the hydrocarbon. This last item falls largely beyond the range of traditional well logging. 4) How producible are the hydrocarbons?. This study attempts to identify the reservoir bodies in the interested interval and the distribution of the sub-environment facies and its impact on the petrophysical properties. Data from wells used in this study include Gamma Ray, Deep

Resistivity, Compressional sonic, Shear sonic, Neutron and Density logs. The interpretation of well-logs was achieved using Schlumberger's Tech Log, 2009 version software and it was conducted on the two wells (X1 and X2) which encountered the Pliocene channel complex as follow: I) Evaluation of petrophysical properties, which includes calculations of Shale Volume (Vsh), Porosity (PHI), Water Saturation (Sw), Net Reservoir and Net pay thickness. II) Lithologic identification of the encountered reservoir units within the Pliocene channel complex for the discrimination of the rocks forming the studied units into shale, sandstone that is very essential in emphasizing the reservoir capability for producing considerable amount of hydrocarbon. In this study, the lithology identification was achieved by the density and neutron crossplots.

Evaluation of petrophysical properties:

The evaluation has been carried out through the following steps: 1) Determination of Shale Volume: Gamma Ray log is a very good shale indicator. It is one of the best tools for identifying and determining the shale volume as a result of the response of the radioactive materials, which is normally concentrated in shaly rocks. The shale volume was calculated according to the following formula (Schlumberger, 1972), Vsh = [GR – GR_{min}] / [GR_{max} – GR_{min}] Where, GR: The reading value of gamma ray log at the analyzed zone. GRmin: The minimum gamma ray value at clean interval. GRmax: The maximum gamma ray value at the shale interval. 2) Determination of Formation Porosity: The formation porosity is very important for calculating the fluid saturation. Porosity can be determined from one of the three porosity logs: sonic, density, and neutron and combination of two of them such as neutron-density and neutron-sonic. In the present work, two types of porosities have been calculated; total porosity which calculates the porosity of the whole interval and effective porosity which calculates the porosity of sandy units and excluding the shale zones. In this study porosity is calculated using neutron and density logs only. A) Total Porosity (ΦNd): The total formation porosity can be determined by combining the results of the density and neutron logs through the following equation (Poupon and Gaymard, 1970). ΦNd = (ΦN + Φd) / 2; where, ΦN is neutron porosity and Φd density porosity. For X1-Well and X2-Well, ρ_{fluid}=0.8 gm/cm^3 (gas sand) and ρ_{fluid}=1 gm/cm^3 (brine sand). B) Effective Porosity (Φeff): The effective porosity depends largely on the degree of connection between the rock pores with each other forming channels, to facilitate the paths of fluids, through the lithologic content. It can be determined using the density-neutron combination through the following equation. Φeff = ΦNd (1- Vsh); where, Vsh is shale volume. For X1-well $\rho_{b\ (shale)}$=1.9546 gm/cm^3 and Nphi=0.5856 and X2-well $\rho_{b\ (shale)}$=2.1733 gm/cm^3 and Nphi=0.557. 3) Determination of Fluid Saturations: The determination of the fluid saturations is very important to complete the deduced petrophysical parameters of the reservoir rocks. Such determination means principally the differentiation between the various types of fluid components (Water and hydrocarbons). The hydrocarbons, in turn, need the separation between the movable and residual types.

A) Water saturations determination: Water saturation has been calculated by using resistivity log, effective porosity log, shale volume log, dual and Indonesia equations. In the present work, the water saturations of the analyzed sand units were calculated in the studied wells from (Indonesia equation) Schlumberger (1972) equation as follow:

$$R\square = \frac{a * Rw}{\Phi^{m}} \quad , \quad C = 1 - (Vsh * 0.5) \quad ,$$

$$A = \frac{Vsh^{c}}{\left(\left[\frac{Rsh}{Rt}\right)\right]^{0.5}} \quad , \quad B = \left(\left[\frac{Rt}{R\square}\right)\right]^{0.5} \quad ,$$

$$Sw = (A + B)^{\frac{-2}{n}}$$

Where, Rt: formation resistivity, Rsh: shale resistivity, Rsh: shale resistivity, a: tortuosity factor, m: cementation exponentand, n: saturation exponent. For X1-Well and X2-Well a=1, m=1.8, n=1.8, R_{shale}=1 Ω.m and Rw=0.082 Ω.m .

B) Hydrocarbon saturations determination: The hydrocarbon saturations are calculated depending on the uninvaded zone and flushed zone water saturation (Sw). The hydrocarbon saturations were determined using the following equation. Sh = 1 – Sw.

Determination of net pay and net reservoir thicknesses:

Reservoir thicknesses have been determined by using summaries module of Techlog software, Vsh log, PHIT_D log, and Sw log. The best cut-off of clay volume, porosity, and water saturation (Vsh, Φeff, and Sw) for channel reservoirs in the studied wells, has been applied to the petrophysical evaluation for such reservoirs. These cut-off parameters are listed as the following:

Min=0 < = val<max=0.35	**Shale Volume_bounds.**
Min= 0.12 < = val<max= 0.35	**Porosity_bounds**
Min=0 < = val<max=0.75	**Sw_bounds**

These parameters are used in calculating net pay and net reservoir thicknesses for each sand element of the channel. Figures (9) and (10) represent the petrophysical evaluation the two wells (X1 and X2) encountered the Pliocene channel complex beside net pay and net reservoir thicknesses of the two wells. Finally, the results indicate that X1 Well consists of three pay zones from four sand packages where the first pay zone form depth 1575 to 1583 m and its Net to Gross is 0.739, the second pay zone from depth 1587.5 to 1619 m and its Net to Gross is 0.442 and the third pay zone from depth 1640.8 to 1647.8 m and its Net to Gross is 0.331. While for X2 Well that consists of one sand package, the pay zone from depth 1638 to 1639.6 m and its Net to Gross is 0.013.

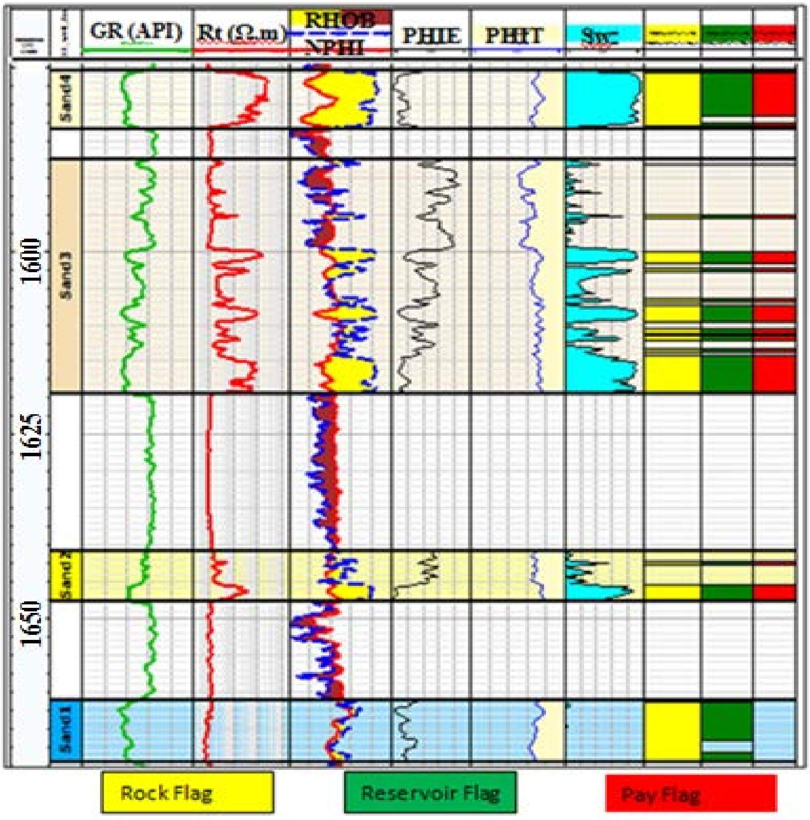

Figure (9): Petrophysical parameters beside net pay and net reservoir thicknesses of the X1-Well.

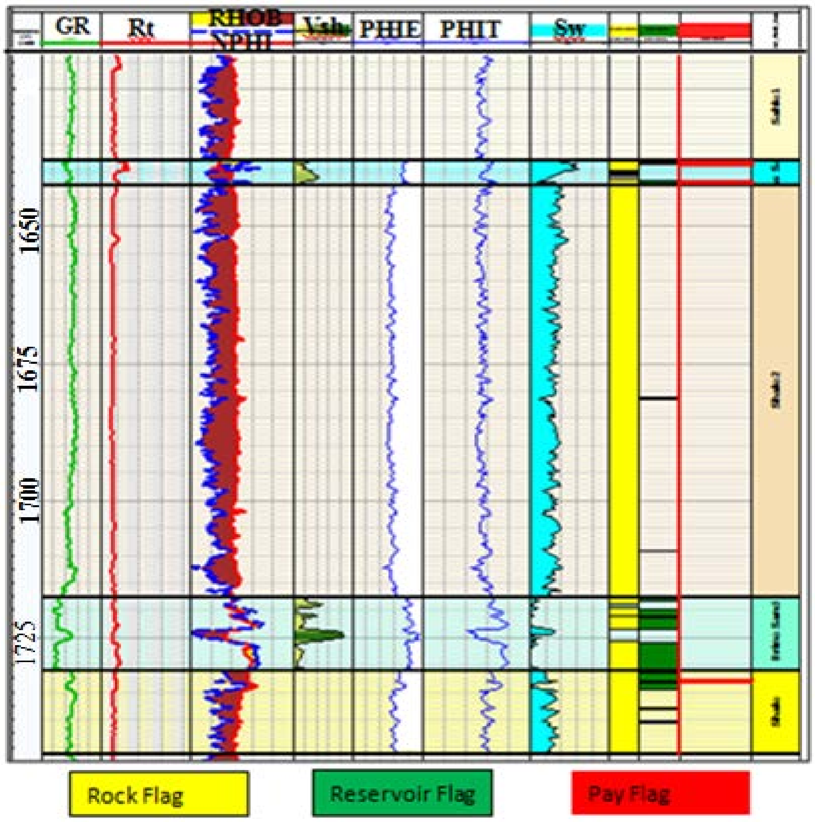

Figure (10): Petrophysical parameters beside net pay and net reservoir thicknesses of the X2-Well.

Table (1): Summary of Pliocene channel complex evaluation.

N/G	Av Sw	Av effective porosity.	Av Vsh	Base	top	Thickness	Reservoir Zone	Well Name
0.739	0.116	0.279	0.105	1583.14	1575.3	7.84	Sand 4	X1 Well
0.442	0.306	0.248	0.131	1619.27	1587.48	31.79	Sand 3	
0.331	0.358	0.215	0.162	1647.65	1640.75	6.9	Sand 2	
-------	------	-------	------	1669.56	1660.95	8.61	Sand 1	
0.013	0.596	0.289	0.251	1746.74	1616.29	130.45	Sand	X2 Well

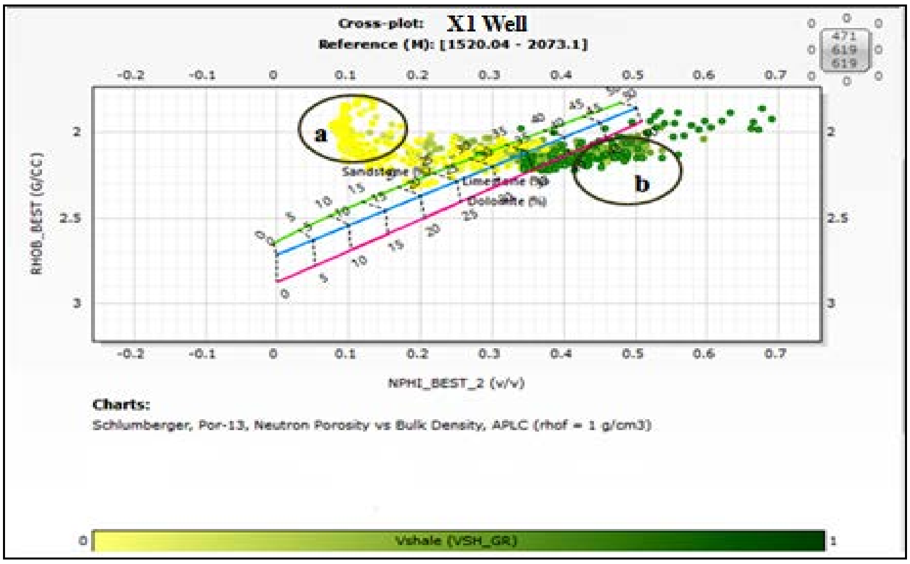

Figure (11): Cross-plot of Neutron porosity and bulk density that shows the zone of gas effect (a) and the shale effect (b) for X1 well.

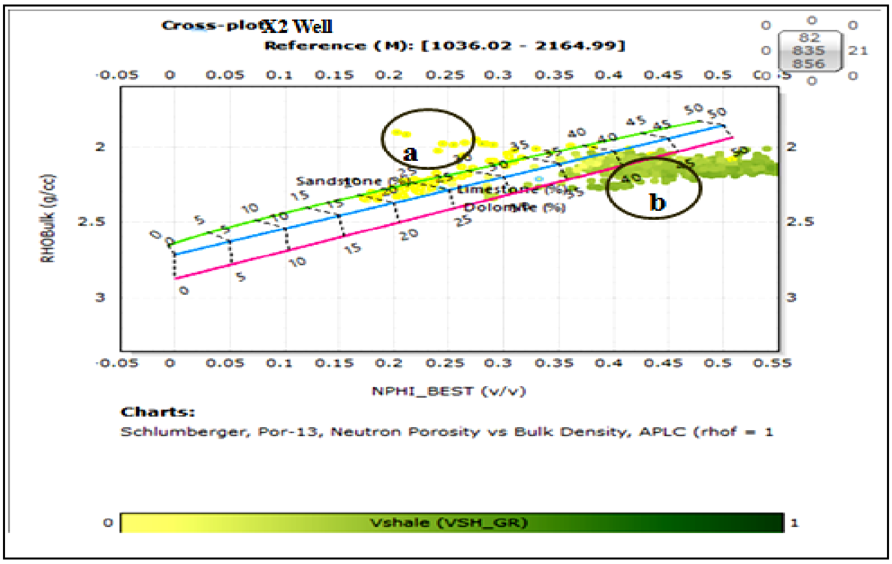

Figure (12): Cross-plot of Neutron porosity and bulk density that shows the zone of gas effect (a) and the shale effect (b) for X2 well.

II) Lithological identification:

In this study, neutron density crossplots were used for lithology identification of the interested zone in the studied wells that aim to discriminate between gas sand and brine sand. In this case, the bulk density (RHOB) and neutron porosity (NPHI) readings are plotted together. Points corresponding to particular water-saturated, pure lithologies define lines (quartz, limestone, dolomite, etc.) which can be graduated in porosity units; or a single zero-porosity point (e.g., salt point) may be defined. When the matrix lithology is a binary mixture (e.g. quartz –limestone or limestone-dolomite) the point plotted from the log readings will fall between the corresponding lithology lines. The effect of gas can be observed on the crossplot, where the plotted data tend to shift north-westerly from the limestone line, since this effect increases porosity determinations from density log and decreases neutron porosity. Also, the effect of shale can be observed on the crossplot, where the shale effects tend to be in the southeast quadrant of the crossplot (Poupon et al., 1971). Figures (11, 12, 13 and 15) represent the neutron-density crossplot for X1 well and X2 well respectively which show the zones of gas sand, brine sand and the shale zones. The final results of the Pliocene channel complex evaluation are represented in table (1).

SUMMARY AND CONCLUSION

The Pliocene channel trap is a 15 Km long, NW-SE curve shaped turbidite channel that is draping over a structural high trending NW-SE. The reservoir distribution and segmentation is highly controlled by faults. Most of these faults (trending NE-SW, Rosetta Fault systems) exploit the planes of weakness in the channel (channel bends). The Pliocene channel system is subdivided into three main segments with different sand distribution. (1) Segment 1 was penetrated by X1 Well. It is composed of a thick sand package of a multi-story stacked channel with different frequencies of the amalgamation surfaces between the channels. This facies is interbedded with a few meters of thin bedded facies. Evaluation of these sand packages indicated that there are three pay zones from four sand packages where the first pay zone form depth 1575 to 1583 m and its Net to Gross is 0.739, the second pay zone from depth 1587.5 to 1619 m and its Net to Gross is 0.442 and the third pay zone from depth 1640.8 to 1647.8 m and its Net to Gross is 0.331. (2) Segment 2 sand distributions is highly controlled by faults, and most channels tend to aggrade vertically against the faults. The channel in this segment shows a laterally accretionary pattern. This segment is not penetrated by any wells. (3) Segment 3 is the main appraisal target for the X2 Well. The sand distribution of this segment is slightly different from Segment 1 and Segment 2. X2 Well will be drilled within the confined system as X1 but the sands at X2 are expected to have less amalgamated nature. Two main sand bodies can be identified as separated by a possible discrete shale package in between. Evaluation of the sand package indicated that the pay zone is from depth 1638 to 1639.6 m and its Net to Gross is 0.013.

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