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Reservoir Compartmentalization and Fluid Properties Determination via Modular Dynamic Tester (MDT): An application for a Case study from an Algerian Oil Field

H. E. Belhouchet · M. S. Benzagouta · A. Dobbi · E. Mazouz · N. Achi · J. Duplay · M. Khodja.

ABSTRACT

Reservoir compartmentalization identification and initial properties determination are key factors for any development of oil field aspects. These characteristics are largely serving for outlining the type and the number of reservoir fluids setting. They are expected to state initial reservoir pressure and reservoir potential. Assessing the potential fluid presence and its range, for each respective zone, comes to be essential. For the case study, the associated reservoirs consist of different respective borehole potentially effective zones where fluid limits remain ambiguous. The applied method in these commitments consists of exploiting recorded pressure using Modular Formation Dynamics Tester tools (MDT) to analyze the pressure gradients and variation. This device is intended to make real-time discrimination and split up between formation fluids. Objectives in that concern are also to define reservoir compartments based on the analytical analysis of pressure gradients, taking into account the reservoir fluid type. Aims in this investigation are conducted towards the identification of the reservoir initial conditions and the setting of the Free Water Level (F.W.L.) for each interesting zone. Thus, in that context, approach on reservoir heterogeneity can be a key factor.

Conducted analysis is related to an oilfield consisting of an anticlinal structure, located in the Saharan platform (South - Eastern of Algeria). This oilfield is part of Hassi Berkine basin. From a sedimentological point of view, the depositional environment has been found as fluvial-continental deposits. Some erosional impacts of the Hercynian discordance were present affecting essentially the top of the Frasnian clays. The main hydrocarbon reservoir consists of the Lower Shaly – Triassic Sandstone Formation (TAG-I): Current designation for the Sahara platform Triassic reservoir in the investigated area. This TAGI has been subdivided into three sub-levels: Upper TAGI (TAGI-U), Middle (TAGI-M) and the Lower (TAGI-L).

Obtained outcomes revealed several pressure gradients versus depth. According to obtained graphs, and statistically, these gradients elucidate, for the same considered borehole section, significant trends. Important to mention that a substantial difference in pressure was observed between the oilfield boreholes e.g. TAGI- U+M and TAGI-L. The equivalent density of these gradients displays a fluid deposit succession as; oil (TAGI-U+M), water (TAGI-M), and oil (TAGI-L). Lithologically, a stratigraphic barrier between TAGI U+M and TAGI-L has been identified. With a superimposed pressure gradients observed in the two wells (1 and 2), two reservoir compartments have been deduced. Furthermore, using pressure evolution versus depth as well as density record, for each reservoir communicated level; two free water levels (F.W.L.), in addition to the initial pressure, were identified.

KEY-WORDS

Porous medium, fluid types, Reservoir pressure, Mobility, Fluid contact.

I. INTRODUCTION

The fluid flow, in a porous medium, is a very complex phenomenon. Identification and selection of the most appropriate solutions must be required to define the main parameters related to the porous medium (Benzagouta, M.S. et al., 2001). Among these parameters are porosity and permeability. Based on literature reviews, several tools have been used to determine these parameters (O. Serra, 1984). Concerning formation porosity, it can be determined using methods such as laboratory core analysis via gas or water injection. Logging tools can support the obtained laboratory results for porosity

evaluation. Among these devices, apte to record porosity are the Computed Tomography (CT), Neutron Density Logging (C.N.L), sonic tools (Δt), Focused Density Log (FDC) and Nuclear Magnetic Resonance tools (NMR) (Hongqi Liu, 2017).

Many reviewers were approaching the porous medium identification and their control on the reservoirs based on case studies (BENZAGOUTA, M. S. and LEE, M. R., 1991), (Benzagouta, M. S. and Amro, M. M., 2009), (Kharraa, H. S. et Al., 2013), (Attia, M.M., Abudeif, A.M., Radwan, A.E., 2015). However, permeability can also be determined from core data, as it can be estimated from N.M.R. and well test interpretation. Similar operating processes are mainly used during the exploration and evaluation activities. Drill Stem Test (DST) and Wire Line Formation Tester (RFT/MDT/XPT/RCI) constitute the principal devices for outcomes. Development activities such as pressure transient testing can also be a close part of the investigation (Belhouchet, H. E. and Benzagouta, M. S., 2019).

Within the porous medium, identification of the stored fluid type is also required, to evaluate fluid volume. In oil and gas industry exploration and production, several techniques were worked out to define fluid type, its location and level of contact. Data coming out from well logs such as NMR, resistivity, density and neutron logs, combined with MDT pressure measurements and fluid samples, yield positive identification of formation fluids type. Additionally the outcomes are allowing determining the oil – water contact (O.W.C.) as well oil – gas contact (O. G.C.), and gas – water contact (G.W.C.) (Abudeif, A. M. et Al., 2018). It is important to mention the distinction between the FWL (free water level) is generally not matching the OWC (oil water contact): they differs by an amount related to the displacement pressure (Elshahawi, H. et al., 1999).

The investigation applied in our case study was through Wireline formation tester (WFT) which is introduced to the oil industry in 1955 (Conrad, K. M., 1962). It was conducted to estimate key parameters such as initial reservoir pressure, local permeability and reservoir fluid type (Abudeif, A. M. et Al., 2018). Support in that circumstances is from (Dubost, F. X. et al., 2007) and (Elshahawi, H. et al., 1999). The use of these parameters can be essential resources for conducting research on the preferential fluid flow stored within the porous medium and furthermore exploring the possibility of perceiving permeability barriers.

Different tools can be used for the purpose of fluid behavior related to the porous medium. Repeat Formation Test (RFT), Reservoir Characterization Instrument (RCI), Modular Formation Dynamics Tester (MDT) and Formation Pressure test log (XPT) are formation tester and sampling tools. They record the formation pressure versus depth at various interval points in the open hole using a wire-line. These tools are also aimed to collect fluid samples (Dybdahl, B. and Hjermstad, H. P., 2001), (Radwan, A. E. et Al., 2020).

In our case investigation and among the previously identified devices, it is the modular dynamic tester (MDT) which has been in use. The concerned tool was conducted for formation evaluation of pressure, temperature, and reservoir quality. One of its aims is the full understanding of the static and dynamic reservoir behavior (Worthington, P. F. et AL., 2012). Formation pressure analysis is very interesting to approach. It is useful in providing information on reservoir quality and compartmentalization (James Howes, 1999). The MDT is correspondingly an accurate tool for delivering statements on reservoir fluid type and free water level (FWL) (Belabed, Malik, 2017).

At the present time, the use of the MDT tool has become indispensable for the development of the oil and gas fields because it provides basic information on the type and number of reservoir fluids and their contacts. The vertical recording made by the MDT provides pressure and mobility measurements at

specific points, chosen according to the log interpretation (Burnie, S. W., and Chen, Z. A., 1998). For accurate readings, points with low mobility and huge values are automatically eliminated. Their removal is own to problems related to the supercharged phenomenon, coupled to severe petrophysical characteristics, degradation, tightness, with sensor blockage (Proett, M. A. and Waid, M. C. , 1997) and (Basioni, M. A. et Al., 2012). Own to accurate representative, and indicative pressure gradients, the elimination of non-significant points, along the concerned reservoir section, must be necessary to state.

In this investigation, the use of pressure gradients is aimed to investigate on the communication between boreholes. Similar task will provide information on the reservoir depletion when drilling a well subsequent to certain production time (Bo Cribbs, 2009). Moreover, pressure gradient change analyses constitute an enhancing support for estimating the original hydrocarbon in place as well as the aquifer activity and assessment. Obtained gradients number will be characterizing fluids types based on their respective setting density values. Thus, a change in pressure gradient will be related to the change in the reservoir fluid type. Hence, the intersection between the two fluid gradients can be interpreted as a credible contact, separating two immiscible fluids in which capillary pressure should be zero. Similar statement is well supported by (Fawakhir, A.Y. et Al., 1989) and (Elshahawi, H. et al., 1999).

Application of the MDT, in the purpose of pressure determination and setting aimed to various gradients evolution, has become necessary for the case study. The pressure distribution is brought up to the well communication probe. Thus, lateral and vertical reservoir continuity and connectivity, with potential fluid contact determination constitute a key factor to be set in the reservoir. The use of data generated from the MDT can also be aimed to permit setting and extending limits for the free water level (F.W.L.) respective for each borehole composed zones. Related tasks will allow finding out the free water level outspread with respect to the surrounding boreholes. Similar outcomes will conduct reaching an overview concerning reservoir heterogeneity. Therefore, the basis of this investigation is stressing on a framework for reservoir compartmentalization in multilayer reservoirs. Therefore, the main objectives of this case study can be set according to available data generated from the MDT as:

- Determination of unconnected reservoir layers.
- Identification of reservoir fluid types and fluid gradient contact setting.
- Determination of fluid type regions.
- Determination of the free water level (F.W.L.) and the identification of the referred pressure.

Application of this investigation is conducted towards some of the Hassi Berkine oil field reservoirs (Algeria). As the concerned reservoirs are involved with similar ambiguous states.

II. GEOLOGICAL SETTING

The Hassi Berkine field was discovered in January 1995 by the SONATRACH/ANADARKO association (Lo, L.L. et Al., 2004). the Berkine Basin is located in south - eastern Algeria, between latitude 29 degrees and 33 degrees north and longitude 5 degrees and 9 degrees East (Belhouchet, H.E., Benzagouta, M.S. Dobbi,A. et Al., 2020). It is limited to the north by the southern border of the Dahar Mole, to the south by the Mole D'Ahara which separates it from the Illizi basin. The concerned basin is bounded to the East by the Tunisian – Libyan borders and finally to the west by the structural extension north of the Amguide – El Biode – Hassi Messaoud Mole. The Berkine Basin is a part of the northern margin of the Saharan platform. It is an intra - or pericratonic basin which has been developed during Middle-Late Triassic times (Turner, P. et Al., 2001) .

The main reservoir in this field is the Lower Triassic Clayey Sandstone (TAGI, French abbreviation for Trias Argilo-Gréseux Inferieur). The thickness of the TAGI varies from 65 meters to 130 meters. TAGI

is of a transgressive nature and lies unconformably on the Paleozoic formations. It is mainly represented by fluvial and lacustrine deposits. Sometimes these deposits are interbedded by aeolian and deltaic layers. Based on the extensive core data and regional interpretation of wireline logs (Benamrane Oussalem, 1987), (Arezki Boudjema, 1987) the TAGI reservoir could be subdivided into three main levels; upper, middle and lower. These levels are subdivided into a total of nine layers (figure 1).

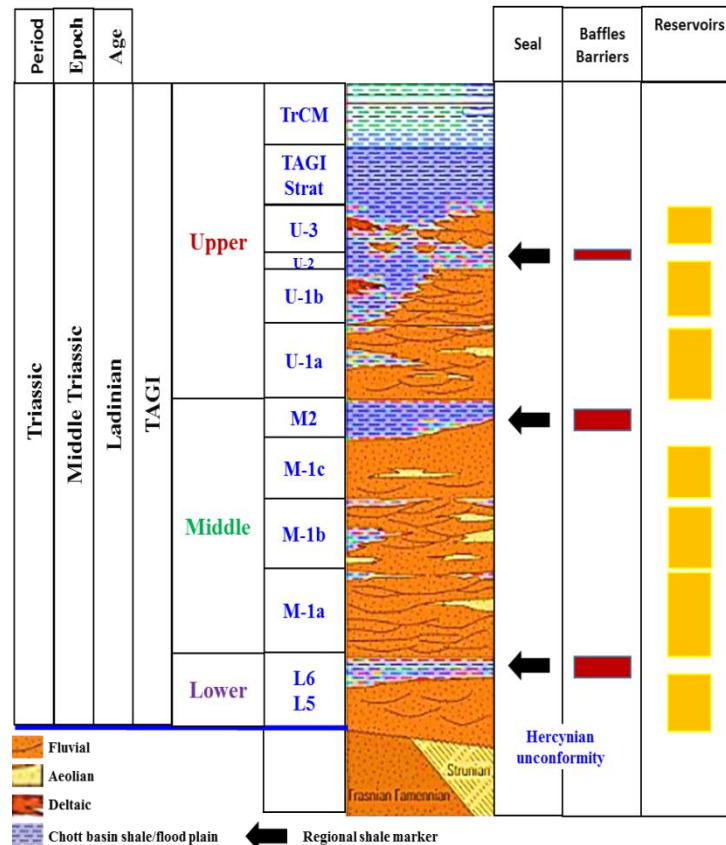


Figure 1: Reservoir subunits in TAGI (Sonatrach WEC, 2007)

Detailed sedimentological and stratigraphic subdivision of the TAGI is as follow is according to (Arezki Boudjema, 1987), (Hamid Aït-Salem, 1990), (Sonatrach WEC, 2007) and (Sayed, A.E. and Bachagha, W. and Benzagouta, M.S., 2017).

The upper TAGI consisting of:

- U1a a sandstone level characterized by fluvial deposits traversed by eolian deposits. This has a good lateral extension.
- U1b a sandstone level whose reservoir qualities deteriorate toward the southeast. It also includes some interbedded deltaic deposits.
- U2 is the clay which is assumed to be regionally continuous and characteristically has small thickness. It is also marked by lacustrine deposits.
- U3 of variable thickness, in which the first sandstone beds interbedded with deltaic deposits are encountered.

The middle TAGI is subdivided into four levels:

- M2 clayish unit, which is assumed to be a lacustrine deposit and of regional extent. It is of very variable thickness.
 - M1c, M1b, and M1a, which are sandstone having generally good reservoir characteristics. They are marked by variable thicknesses according to the local distribution of channels.
- Level M1 shows the greatest variation in thickness.

The lower TAGI, which lies directly on the hercynian unconformity, is subdivided into two levels

- L5 a sandstone characterized by fluvatile deposits.
- L6 representing the clay.

In the conducted case, an investigation is concerned with TAGI formation assembling three wells: well-1, well-2 and well-3 belonging to the Hassi Berkine basin (figure 2). The reservoir characteristics analysis has been found of relatively up to good quality porosity. It is varying from 7 to 20 % whereas the permeability is found fluctuating from 1 millidarcies to 850 millidarcies (mD) (Belhouchet, H.E., Benzagouta, M.S. Dobbi, A. et Al., 2020). The initial development plan called a first stage of production during the first 5 years was at the rate of 5000 Stb/day. This production is supported by water injection at the reservoir peripheral. Initial well tests carried out on the well-2 were indicator of an excellent sandstone reservoir (TAGI) with a flow of 4500 Stb/day. It is important to mention that no water cut (WCT) has been observed.

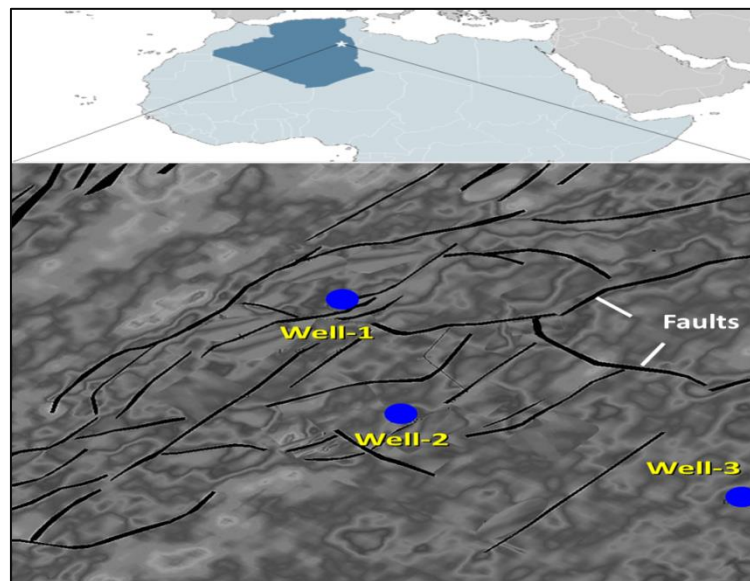


Figure 2: Wells position map

III. MATERIAL AND METHODOLOGY OF INVESTIGATION

Interest in the case study area were wells 1, 2 and 3 drilled in the area of Hassi Berkine oilfield basin (figure 2). Available data includes pressure data recorded using Modular Formation Dynamics Tester (MDT) or Formation Pressure Tester Tools (F.P.T.T.). These tools are aimed to provide along the concerned reservoir section, pressure and mobility measurements. The recorded data is established at specific selected points, according to the well log interpretation.

The number of selected points could be depending on the thickness of the reservoir layer. According to the tool efficiency (MDT) in the case study, four to six points can be selected for each reservoir layer,

depending on the tasks. Restriction in this methodology procedure is to automatically eliminate data with low or huge mobility values. This task is intended to avoid supercharged phenomenon such as: severe petrophysical characteristics degradation, tightness and the sensor blockage. The elimination of non-significant points must be necessary to have a representative and indicative pressure measurements and gradients. Table (see [#Appendix](#)) is indicator of the considered data in that purpose.

Conducted investigation can be referred to reservoir pressure parameter. This considered factor can be a useful device in indicating a static linear-gradient contingent on the fluid's density (water, brines, oil, and gas) in the pore spaces (Selim S. Shaker, (2012). Support in that purpose can be through the pore pressure of the reservoirs (Radwan, A. E. et Al., 2019). Stated equations are as follow:

$$P_z = 0.433 * \text{Fluid Density} * Z \quad (1)$$

Thus, the gradient can be calculated by Fooshee, Jeffrey Steven, 2009:

$$\text{Fluid Gradient (psi/ft)} = \frac{P_z}{Z} = 0.433 * \text{Fluid Density} \quad (2)$$

P_z ; Pressure at depth

Z; Depth

Using the equation (2), the fluid density can be calculated based on gradient observed graphically according to the following formula:

$$\text{Fluid Density} = \text{Fluid Gradient} / 0.433 \quad (3)$$

Oil-field liquids and gases occur in a wide range of compositions. The table below shows typical density ranges and gradients for gas, oil, and water. However, own to exceptions occurrences, some expected fluid types might present their own appropriate values (Fooshee, Jeffrey Steven, 2009). Thus, fluid density outcomes in our case study can be derived from (Table 1).

Fluid	Normal Density range (g/cm3)	Gradient (psi/feet)
Gaz (Gazeux)	0.007 – 0.3	0.003 – 1.13
Gaz (liquide)	0.2 – 0.4	0.09 – 0.174
Oil	0.4 – 1.2	0.174 – 0.486
Water or Brine	1 – 1.15	0.433 – 0.50

Table 1: Table showing the fluid density and Gradient ranges for different fluids (AAPG WIKI, 2015)

IV. RESULTS AND INTERPRETATION

In order to calculate the pressure gradients at the wells drilled from the MDT data, quality control of the recorded points must be carried out. The led process for the case study was based on the pressure quantity recorded in relation to the actual pressure. The oversized pressures have been eliminated automatically. This subtraction depends on the measured mobility: Specifically points of low mobility, their occurrence can be own to the degradation of petrophysical characteristics. The dimensionless mobility points were related to the presence of fractures or sealing problems. These two cases of mobility; minimal and dimensionless were directly eliminated. The remaining points have constituted the most representative measurements. They afford a better illustration of the pressure gradients giving a possibility to identify the static and dynamic reservoir behaviors. According to the MDT obtained results for the case study, three main interpretation steps were set.

A. Determination of unconnected reservoir layers and reservoir fluid type

The first step consists of locally processing the MDT records. The obtained data from exploration wells are intended to determine the number of unconnected reservoir layers and identify the type of reservoir fluid. Different boreholes were considered in the purpose of obtaining maximum information on fluid distribution and contact in addition to reservoir heterogeneities (Belhouchet, H.E., Benzagouta, M.S. Dobbi, A. et Al., 2020).

1) WELL-1

Well-1 is the first exploration well drilled in the north west of the field. The well location and pressure reordered from formation pressure tester (MDT) are illustrated in figure 3. Results and interpretation, based on formation pressure tester, for the case study, have been found very significant towards reservoir type. Different compartments were defined on the basis of pressure versus depth (figure 3). Using this tool, in the case study, is own to its performance in that considered topic (Noah, A. Z., 2014). The acquired compartments revealed more useful information on the possible heterogeneities of the reservoir, which can be closely related to the presence of a number of permeability barriers (figure 4).

According to the graphical analysis, with pressure versus depth, several pressure gradients with statistically significant trends have been found, for the same considered well (figure 3). The range of pressure gradients occurring in the first exploration well might be related to the presence of two distinct reservoir layers being separated by shale barriers (figure 4). Based on graphical interpretation, with pressure versus depth, three pressure gradients were defined: 0.34 psi/feet in the upper TAGI, 0.47 psi/feet in the middle TAGI and 0.3 psi/feet in the lower TAGI. In order to estimate the equivalent density, equation 3 was applied. Depending on the results obtained, the reservoir layers were characterized by three different reservoir fluids based on their specific density: the first fluid with a density of 0.78 kg/l in TAGI-U, in TAGI-M, the fluid characterized by a density of 1.08 kg/l, and the third fluid in TAGI-L with a density of 0.69 kg/l (Table 2).

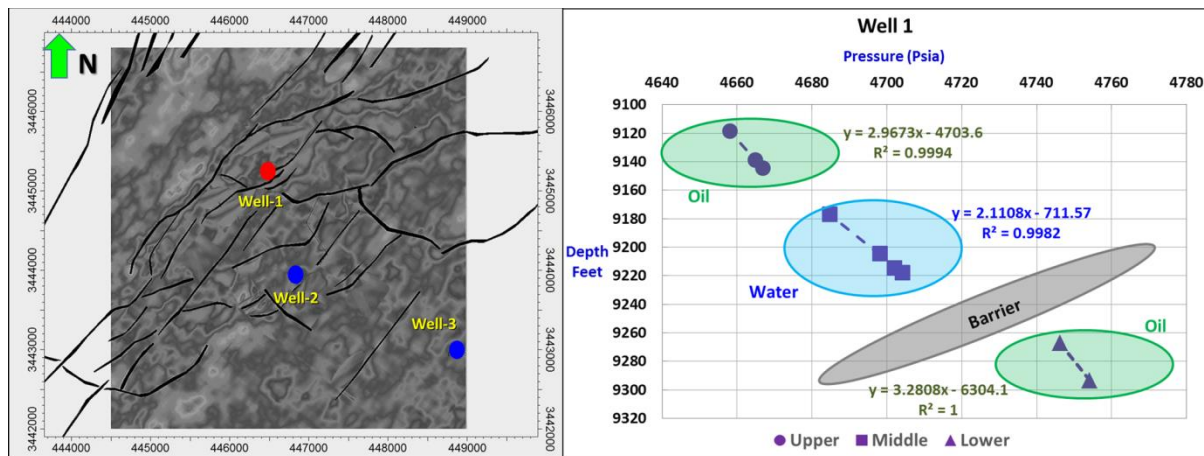


Figure 3: Well location and pressure reordered from formation pressure tester (MDT) for Well-1

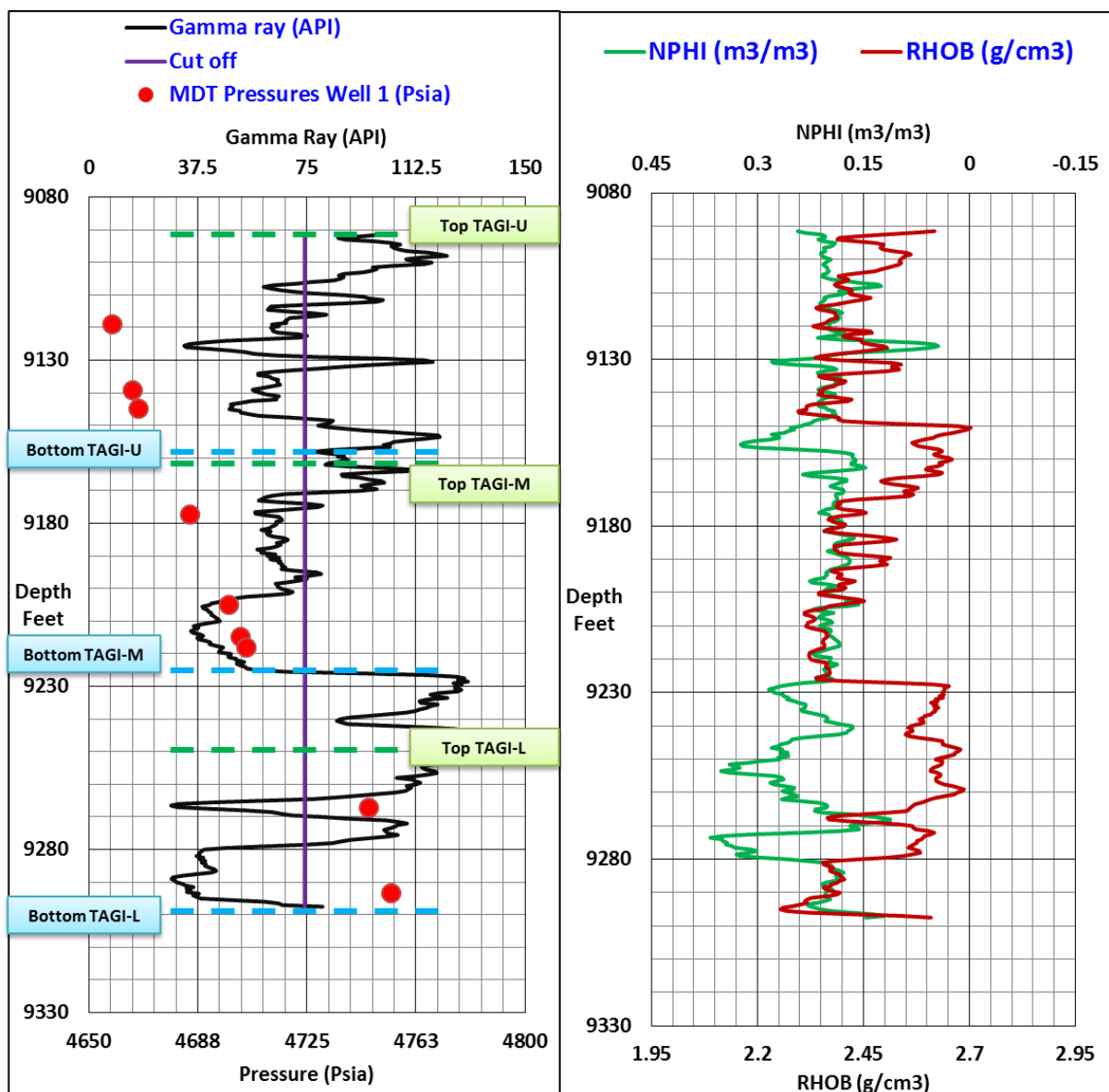


Figure 4: Well logs; Gamma ray, RHOB and NPHI, including the MDT measurements in the Well-1

Wells	Level	Gradient (psi/feet)	d(lb/gal)	d(kg/m3)	d(kg/l)	Fluid
WELL-1	TAGI-U	0.34	6.53846	783.48048	0.78	Oil
WELL-1	TAGI-M	0.47	9.03846	1083.04655	1.08	Water
WELL-1	TAGI-L	0.3	5.76923	691.30631	0.69	Oil

Table 2: Pressure gradients and fluid densities interpreted for the Well-1

2) WELL-2

This well was drilled in the central part of the field with the aim of crossing all the reservoir sections for collecting useful information, and to acquire pressure gradients in the desired area. The location of the concerned wells with the MDT records is shown in figure 5.

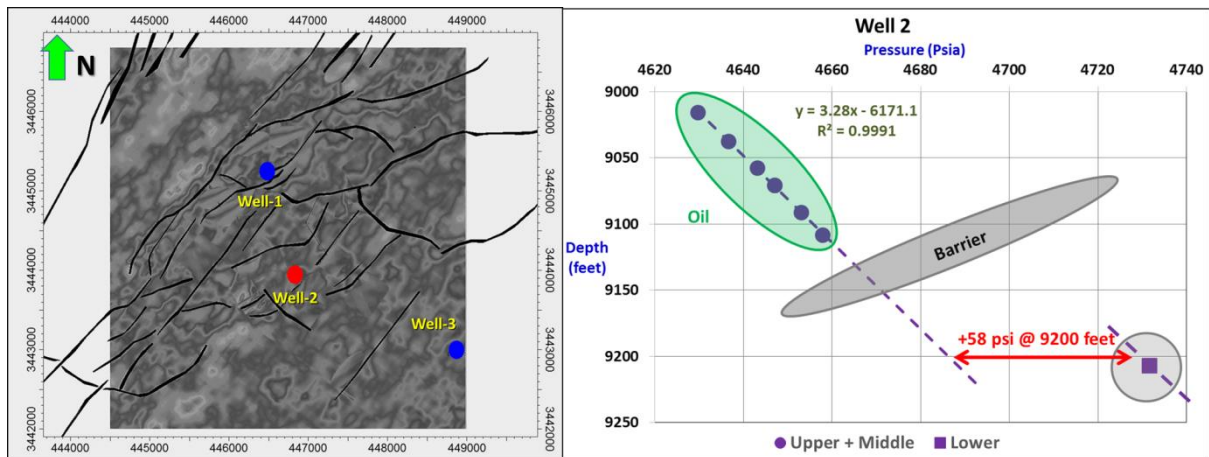


Figure 5: Well location and recorded pressure from formation pressure tester (MDT) for well-2

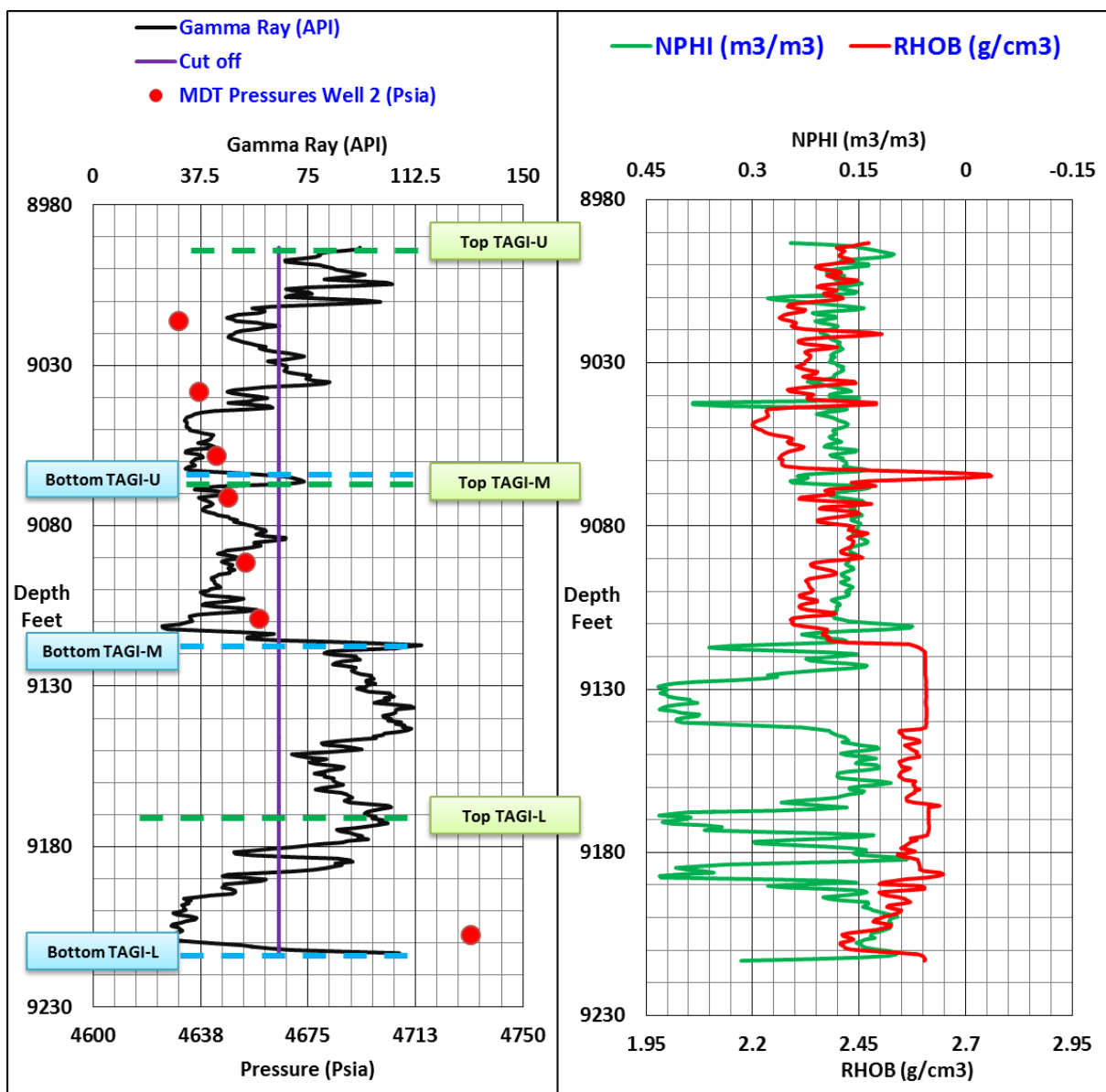


Figure 6: Well logs; Gamma ray, RHOB and NPHI, including the MDT measurements for Well-2

Graphical analyses, using the formation pressure tester records, for well-2, revealed the same results as in well-1. Two separately gradients have been selected: first in the upper and middle reservoir part and the second gradient was pointing up along the lower considered reservoir section (figure 5). The pressure gradients, presented in the upper and middle reservoir sections, show that the fluid reservoir could be the oil according to the defined gradient 0.3048 Psi/feet. This gradient is similar to that gradient observed in the TAGI-L (well-1), and therefore, the same fluid has been proven in the two reservoir levels TAGI U+M for the well-2 (table 3) and TAGI-L for the well-1 (table 2). Although the presence of a single point in the lower part of the reservoir gives information on the pressure dimension, but it remains insufficient for determining the pressure gradient for this reservoir level.

An identical gradient has been identified in the upper and middle reservoir sections (figure 5). It means that these upper and middle reservoirs can be treated as in dynamic communication. Assuming that, the same type of reservoir fluid was presented in the TAGI-L. Additionally and according to the gradient profiles passing through the points recorded in the TAGI U + M and the TAGI-L at depth -9200 feet, a difference of 58 Psi was observed between the Upper-Middle and Lower reservoir sections (figure 4). This distinction can be obviously related to the presence of a likely lithologic barrier between the two zones (figure 6).

Wells	Level	Gradient (psi/feet)	d(lb/gal)	d(kg/m3)	d(kg/l)	Fluid
WELL-2	TAGI-U	0.3	5.76923	691.30631	0.69	Oil
WELL-2	TAGI-M	0.3	5.76923	691.30631	0.69	Oil
WELL-2	TAGI-L	-	-	-	-	-

Table 3: Pressure gradients and fluid densities interpreted for the well-2

3) WELL-3

After confirmation of the presence of the two reservoir fluids, a third well has been proposed to be drilled in the aquifer zone. Among objective in that purpose was the topping of the free water level (F.W.L.) in both reservoirs; upper, middle and lower part. The location of the well and pressure reordered from formation pressure tester (MDT) is illustrated in figure 7.

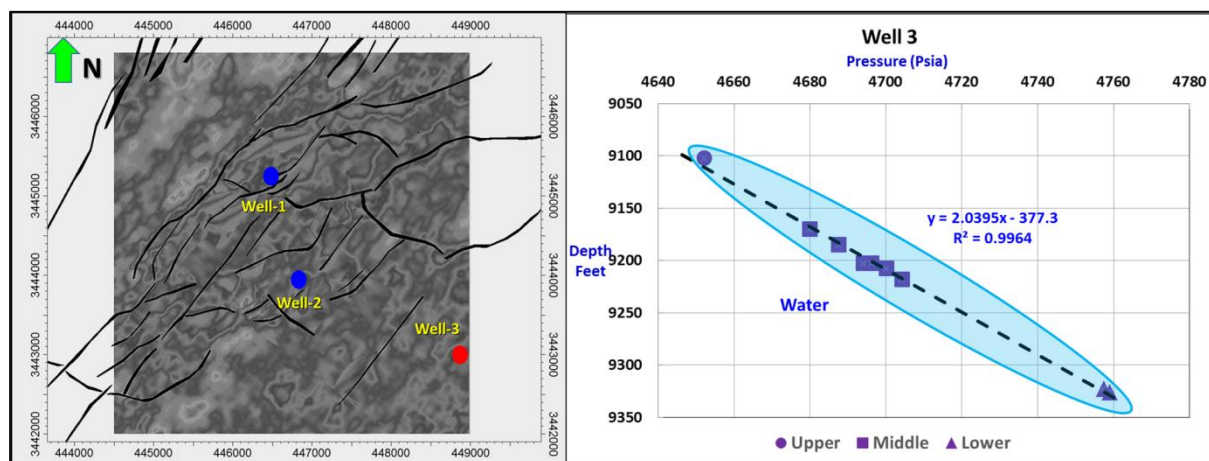


Figure 7: Well location and pressure reordered from formation pressure tester (MDT) for well-3 with focus on water setting level

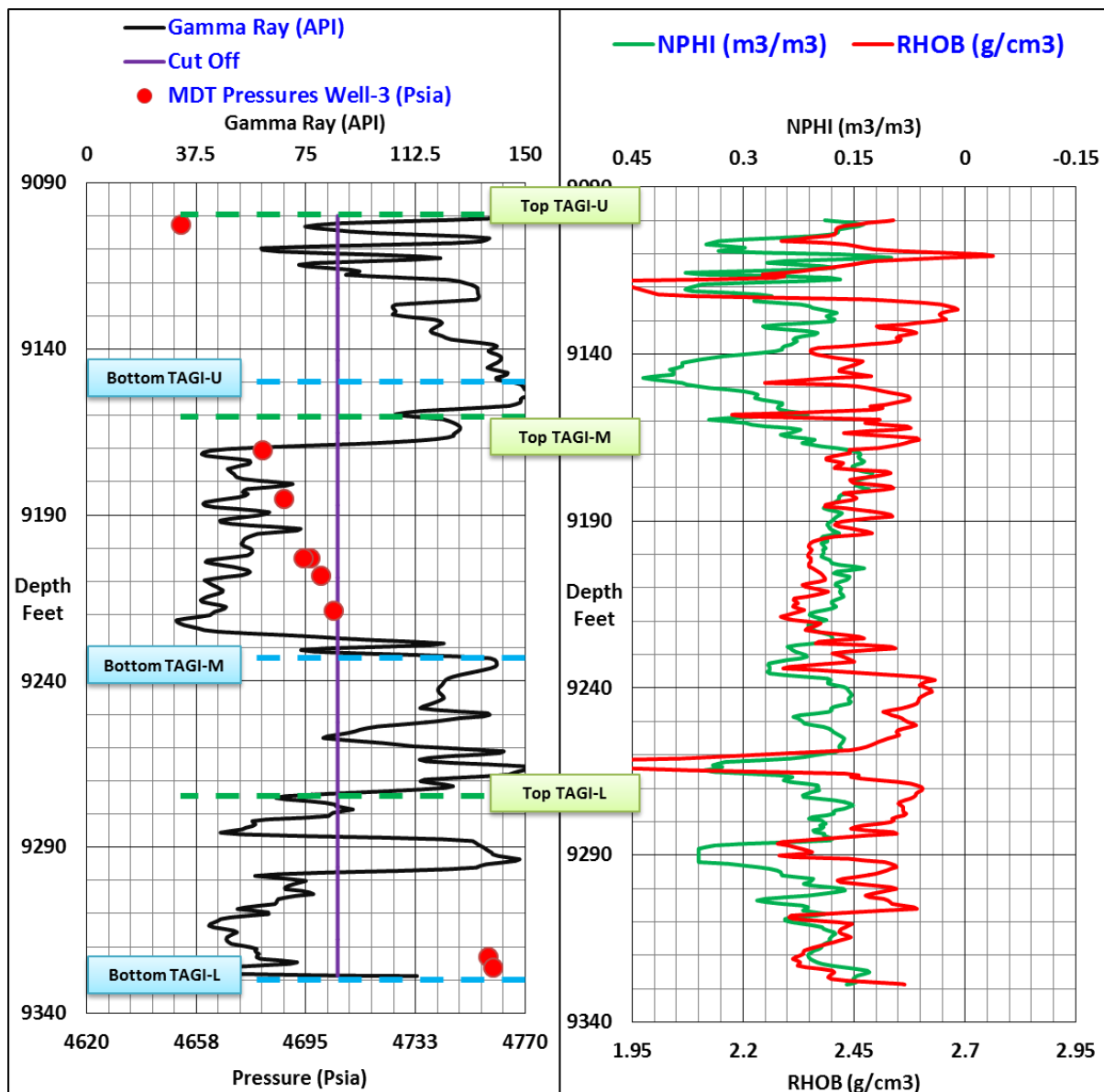


Figure 8: Well logs; Gamma ray, RHOB and NPHI, including the MDT measurements in the well-3

Regarding the figure 7, the formation pressure tester analysis (F.P.T.A.) shows the same pressure gradient profile for the upper, middle and lower reservoir sections. The implication of the gamma ray log is indicator of a stratigraphic barrier between these reservoir levels (figure 8). This statement can be, in terms of lithology, a stratigraphic barriers being revealed using well logs, Implication of pressure gradients which is the same, essentially in the TAGI-M and TAGI-L, is revealing that the three reservoir levels have been saturated by the same fluid type, a communication path is probable. Thus, the stratigraphic barrier is discontinuous or disjointed. The recorded pressure gradient in this well is about 0.51 psi/ft. Similar value is corresponding to water fluid in table 4. Thus, this is revealing that the drilled borehole reservoir is a water fluid type. Depending on the location of the aquifer zone in this considered borehole, recommended is to use its own specific data information for establishing the free water level (F.W.L.) and its extend.

Wells	Level	Gradient (psi/feet)	d(lb/gal)	d(kg/m3)	d(kg/l)	Fluid
WELL-3	TAGI-U	0.51	9.80769	1175.22073	1.18	Water
WELL-3	TAGI-L	0.51	9.80769	1175.22073	1.18	Water

Table 4: Pressure gradients and fluid densities interpretation for the well-3

B. Fluid Type (PVT) Regions Identification

Based on the pressure gradients defined in the previous section, the density of the reservoir fluid was calculated for each reservoir level. According to the obtained results, several reservoir fluid types have been expected. Similar results constitute the main support for going through reservoir compartmentalization. Thus, the need for the determination of the fluid type regions should be necessary.

An analytical examination of MDT pressure recorded is showing the presence of two oil gradients which are: 0.34 psi/feet and 0.3 psi/feet. Based on these gradients, the densities of reservoir fluids were calculated by applying the equation 3. The first estimated density is 0.78 kg/l in the upper TAGI located in the western zone of the field (well-1 zone). The second extracted density is 0.69 kg/l corresponding to the lower TAGI, situated in the same zone (well-1 zone). The same density of 0.69 kg/l has been obtained for TAGI U+M in the eastern zone (well-2 zone). In view of that results, two PVT regions were defined; PVT region 1 in the upper TAGI of the western area of the field (TAGI-U), and PVT region 2 in the lower TAGI of the western area, and TAGI U+M for the eastern area of the field. For accurate support and statement deduction, summarized pressure gradients and estimated fluid density outcomes are sited in table 5.

Wells	Level	Gradient (psi/feet)	Fluid Density (lb/gal)	Fluid Density (kg/m3)	Fluid Density (kg/l)	Fluid Type
Well-1	TAGI-U	0.34	6.53846	783.48048	0.78	Oil
Well-1	TAGI-M	0.47	9.03846	1083.04655	1.08	Water
Well-1	TAGI-L	0.3	5.76923	691.30631	0.69	Oil
Well-2	TAGI-U	0.3	5.76923	691.30631	0.69	Oil
Well-2	TAGI-M	0.3	5.76923	691.30631	0.69	Oil
Well-3	TAGI-M	0.51	9.80769	1175.22073	1.18	Water
Well-3	TAGI-L	0.51	9.80769	1175.22073	1.18	Water

Table 5: Pressure gradients and deduced fluid densities for the considered case study boreholes

C. Free Water Level and Reference Pressure Determination

The third phase is effectively based on the general view of the field. It focuses mainly on exploiting the gradients measured at all exploration boreholes to determine the free water level (F.W.L.) and the referred pressure. The free water level identification (F.W.L.) is one of the main variables used to define the reservoir compartments. To determine the F.W.L., the use of M.D.T. data, prior to production starting-up, must be required essentially. The first step in this action is to interpret the formation pressure tester data to define reservoir compartments at each well. The graphical analysis of pressure gradients, measured and recorded from the two drilled wells (well-1 and well-2), has shown that TAGI reservoir could be subdivided, according to pressure profile, into two compartments: the first compartment corresponds to the upper - middle reservoir section, whereas the second compartment can be allocated to the lower part (figures 3 and 5).

The combination of the different pressure gradients versus depth, derived from the various neighboring boreholes, permit the set of the free water level (F.W.L.) at each considered reservoir. The graphical analysis of the formation pressure tester data shows the presence of two possible free water levels, the first one is located in the upper – middle TAGI and has been set at -9147.5 feet, and the second in the lower TAGI is expected at -9360.6 feet (figure 9). For precision, pressure equation parameters, used for F.W.L. determination for TAGI reservoir levels, are illustrated in tables 6 and 7.

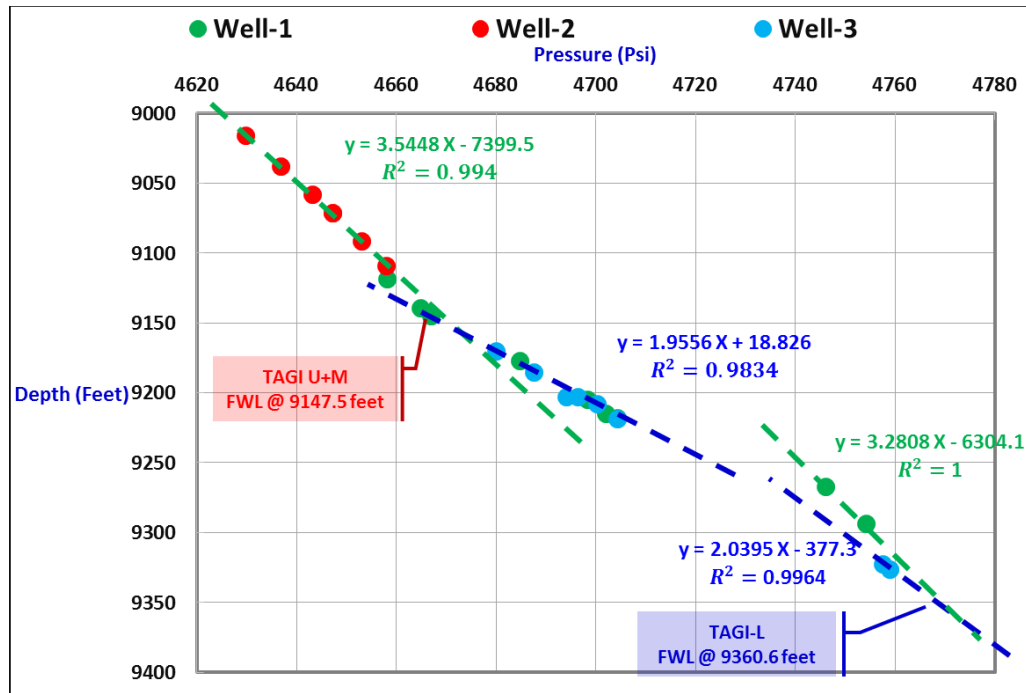


Figure 9: Formation pressure tester results recorded in the upper - middle and lower TAGI reservoirs of the exploration wells

TAGI U+M			
Oil equation		Water equation	
A	3.5448	A'	1.9556
B	-7399.5	B'	18.826

Table 6: Pressure equation parameters used for F.W.L. determination for TAGI U+M

TAGI-L			
Oil equation		Water equation	
A	3.2808	A'	2.0395
B	-6304.1	B'	-377.3

Table 7: Pressure equation parameters used for F.W.L. determination for TAGI-L

Regarding the well gradients observed in the two wells (1 and 2), the pressure gradients characteristics are superimposed with a slight deviation. This change in gradient can be explained by the possible petrophysical characteristics degradation affecting differentially those two wells. It can also be related to the change in reservoir fluid type, especially in the TAGI-U. In terms of pressure similarities, these wells may suggest a scenario of being in a dynamic communication (table 8).

Similar graphical results have allowed the estimation of the initial pressure for each reservoir layer respectively: 4668 Psi in upper and middle sections and 4775 Psi in the lower section (table 8).

Regions	FWL (feet)	Reference Pressure (Psi)
TAGI U (East Zone) + TAGI M	9147.5	4668
TAGI U (West Zone)	9147.2	4668
TAGI- L	9360.6	4775

Table 8: Reference Pressures, free water level and reservoir regions

V. CONCLUSION

Modular dynamic tester (MDT), in relation to pressure evolution versus depth, constitutes a useful tool to be used efficiently in order to split up the limit between the different fluids, stored in the porous medium. Variation in pressure gradient is an interesting parameter being collected and used for information regarding fluid characteristics type and possibly lithology nature. These pressure gradients were also an adequate device to reveal the possible dynamic communication between the boreholes. In addition, modular dynamic tester was a successful device to set gradients change aimed to especially establish not only the different fluid contacts including the free water level (F.W.L.) but also the vertical and lateral ambiguities regarding fluid dynamism and heterogeneities.

The prediction of the type, number and physical characteristics of the reservoir fluid, and initial reservoir pressure by MDT tools constitute the main factors for the surface facilities aspects.

Reservoir compartments, reference pressure, free water level, PVT regions determination are the main inputs for reservoir model initialization. The overall has got a significant impact on the quality of simulation results.

The determination of the free water level (F.W.L.) reflects the initial conditions of the field that have a very significant impact on the estimation of the original oil in place (OOIP). Accordingly, this F.W.L. can be considered as one of the main factors involved for the field development plan preparation.

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VII. CONFLICT OF INTEREST STATEMENT

The authors have no conflict of interest to report.

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452

Wells	Depth (feet)	Pressure (Psia)	Mobility	Observation	Formation
Well-1	9108	-	-	Supercharging	TAGI-U
Well-1	9119	4658	5.42	representative	TAGI-U
Well-1	9139	4665	35.01	representative	TAGI-U
Well-1	9145	4667	145.05	representative	TAGI-U
Well-1	9177	4685	7.55	representative	TAGI-M
Well-1	9205	4698	82.36	representative	TAGI-M
Well-1	9215	4702	42.6	representative	TAGI-M
Well-1	9218	4704	51.9	representative	TAGI-M
Well-1	9267	4746	65.3	representative	TAGI-L
Well-1	9289	5656	-	Oversized Pressure – Not representative	TAGI-L
Well-1	9294	4754	13.56	representative	TAGI-L
Well-2	9016	4630	72.63	representative	TAGI-U
Well-2	9038	4637	250	representative	TAGI-U
Well-2	9058	4643	180	representative	TAGI-U
Well-2	9071	4647	68.21	representative	TAGI-M
Well-2	9071	4647	7.06	representative	TAGI-M
Well-2	9092	4653	14.32	representative	TAGI-M
Well-2	9109	4658	21.34	representative	TAGI-M
Well-2	9201	-	-	Supercharging	TAGI-L
Well-2	9207	4732	35.2	representative	TAGI-L
Well-3	9103	4652	0.34	Tight	TAGI-U
Well-3	9114	-	-	Supercharging	TAGI-U
Well-3	9171	4680	9.4	representative	TAGI-M
Well-3	9185	4688	37.26	representative	TAGI-M
Well-3	9203	4694	16.34	representative	TAGI-M
Well-3	9203	4696	67.35	representative	TAGI-M
Well-3	9208	4700	195.64	representative	TAGI-M
Well-3	9219	4704	189.4	representative	TAGI-M
Well-3	9308	-	-	Supercharging	TAGI-L
Well-3	9323	4758	27.5	representative	TAGI-L
Well-3	9326	4759	6.5	representative	TAGI-L