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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 plateforem 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

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

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

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

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

72 Different tools can be used for the purpose of fluid behavior related to the porous medium. Repeat
73 Formation Test (RFT), Reservoir Characterization Instrument (RCI), Modular Formation Dynamics
74 Tester (MDT) and Formation Pressure test log (XPT) are formation tester and sampling
75 tools. They record the formation pressure versus depth at various interval points in the open hole using
76 a wire-line. These tools are also aimed to collect fluid samples (Dybdahl, B. and Hjermstad, H. P.,
77 2001), (Radwan, A. E. et Al., 2020).

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

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

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

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

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

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

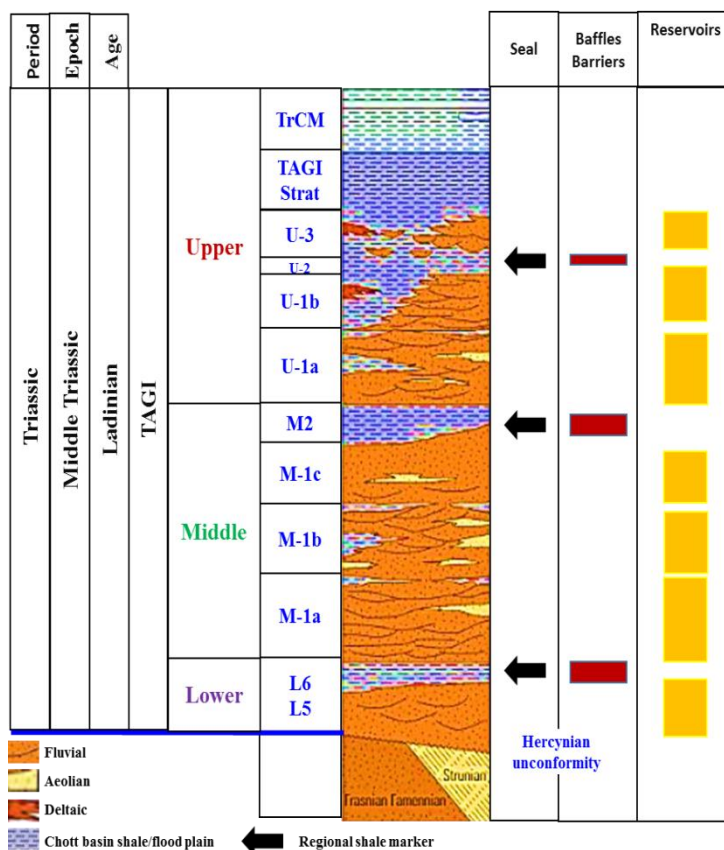
117 Application of this investigation is conducted towards some of the Hassi Berkine oil field reservoirs
118 (Algeria). As the concerned reservoirs are involved with similar ambiguous states.

119 **II. GEOLOGICAL SETTING**

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

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

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



136

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

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

141 The upper TAGI consisting of:

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

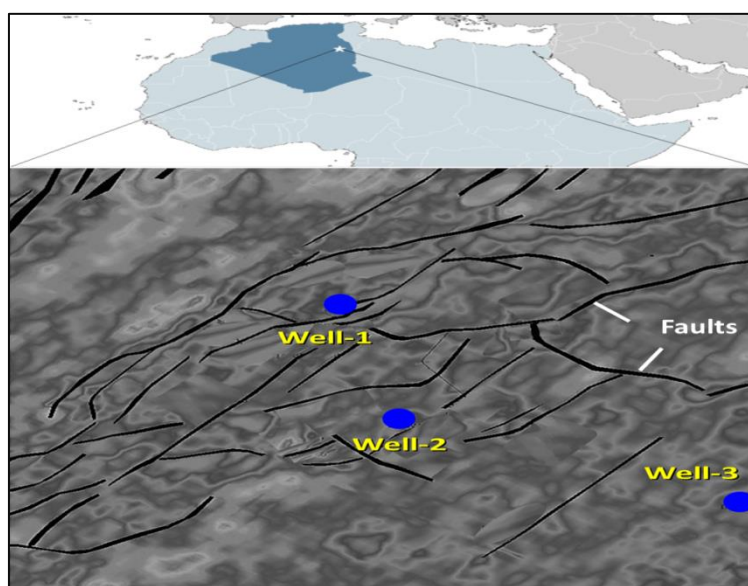
150 The middle TAGI is subdivided into four levels:

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

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

- 157 - L5 a sandstone characterized by fluvial deposits.
- 158 - L6 representing the clay.

159 In the conducted case, an investigation is concerned with TAGI formation assembling three wells: well-
 160 1, well-2 and well-3 belonging to the Hassi Berkine basin (figure 2). The reservoir characteristics
 161 analysis has been found of relatively up to good quality porosity. It is varying from 7 to 20 % whereas
 162 the permeability is found fluctuating from 1 millidarcies to 850 millidarcies (mD) (Belhouchet, H.E.,
 163 Benzagouta, M.S. Dobb, A. et Al., 2020). The initial development plan called a first stage of production
 164 during the first 5 years was at the rate of 5000 Stb/day. This production is supported by water injection
 165 at the reservoir peripheral. Initial well tests carried out on the well-2 were indicator of an excellent
 166 sandstone reservoir (TAGI) with a flow of 4500 Stb/day. It is important to mention that no water cut
 167 (WCT) has been observed.



168

169

Figure 2: Wells position map

170 III. MATERIAL AND METHODOLOGY OF INVESTIGATION

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

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

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

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

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

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

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

188 P_z ; Pressure at depth

189 Z; Depth

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

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

192 Oil-field liquids and gases occur in a wide range of compositions. The table below shows typical density
 193 ranges and gradients for gas, oil, and water. However, own to exceptions occurrences, some expected
 194 fluid types might present their own appropriate values (Fooshee, Jeffrey Steven, 2009). Thus, fluid
 195 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

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

197 **IV. RESULTS AND INTERPRETATION**

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

208 **A. Determination of unconnected reservoir layers and reservoir fluid type**

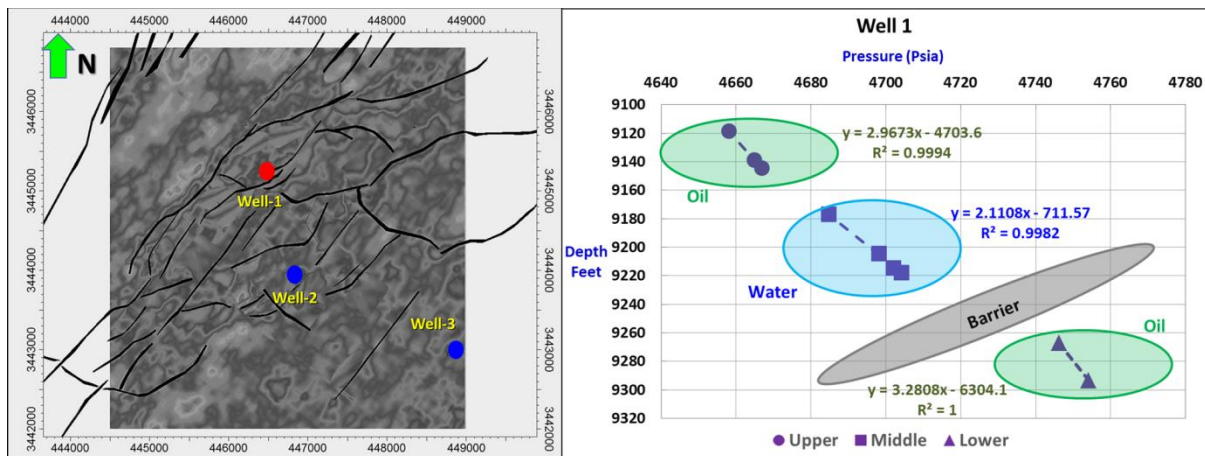
209 The first step consists of locally processing the MDT records. The obtained data from exploration wells
210 are intended to determine the number of unconnected reservoir layers and identify the type of reservoir
211 fluid. Different boreholes were considered in the purpose of obtaining maximum information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

214 **1) WELL-1**

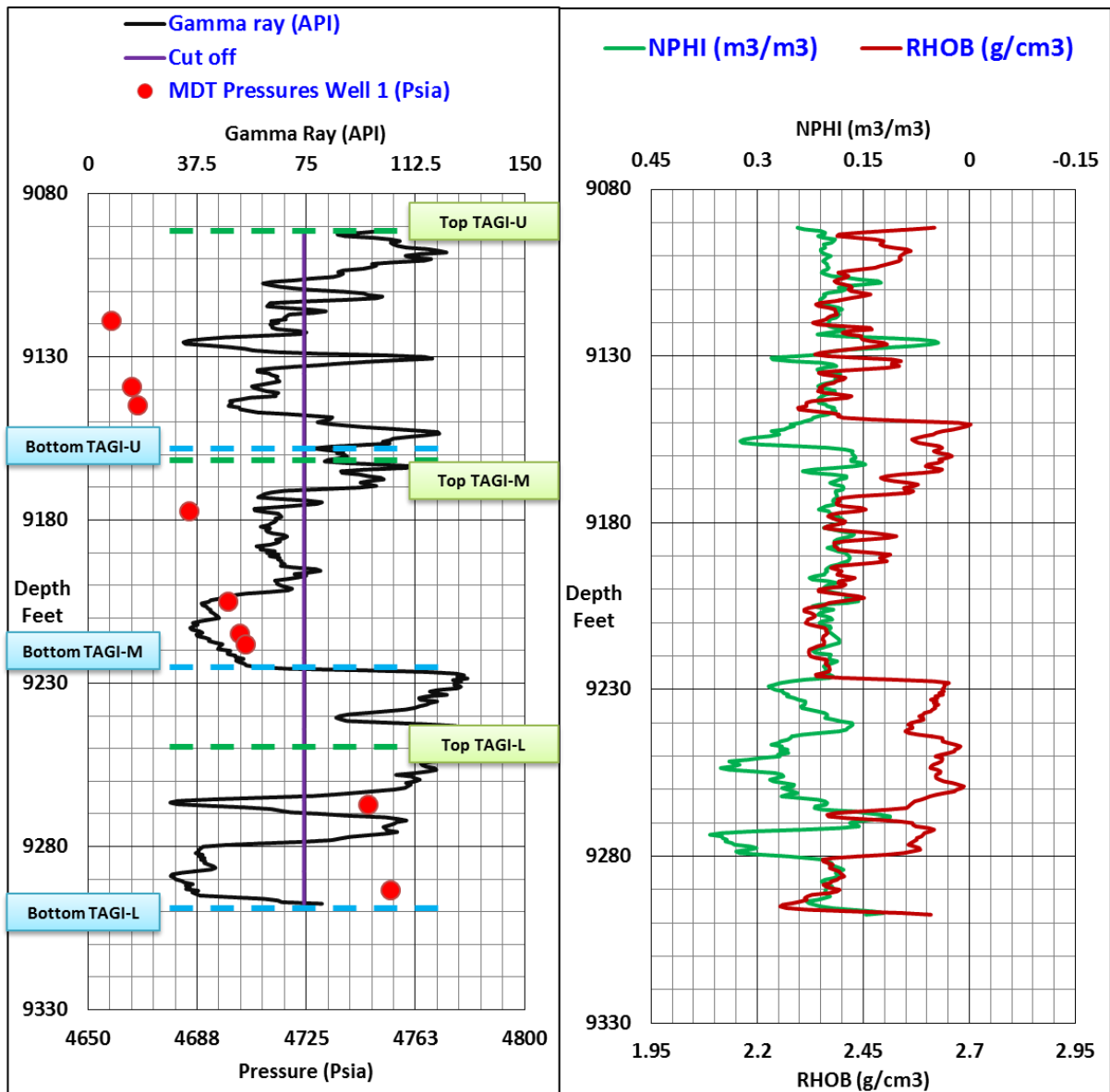
215 Well-1 is the first exploration well drilled in the north west of the field. The well location and pressure
216 reordered from formation pressure tester (MDT) are illustrated in figure 3. Results and interpretation,
217 based on formation pressure tester, for the case study, have been found very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

222 According to the graphical analysis, with pressure versus depth, several pressure gradients with
223 statistically significant trends have been found, for the same considered well (figure 3). The range of
224 pressure gradients occurring in the first exploration well might be related to the presence of two distinct
225 reservoir layers being separated by shale barriers (figure 4). Based on graphical interpretation, with
226 pressure versus depth, three pressure gradients were defined: 0.34 psi/feet in the upper TAGI, 0.47
227 psi/feet in the middle TAGI and 0.3 psi/feet in the lower TAGI. In order to estimate the equivalent
228 density, equation 3 was applied. Depending on the results obtained, the reservoir layers were
229 characterized by three different reservoir fluids based on their specific density: the first fluid with a
230 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
231 third fluid in TAGI-L with a density of 0.69 kg/l (Table 2).

232



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



234

235 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

236

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

237

2) *WELL-2*

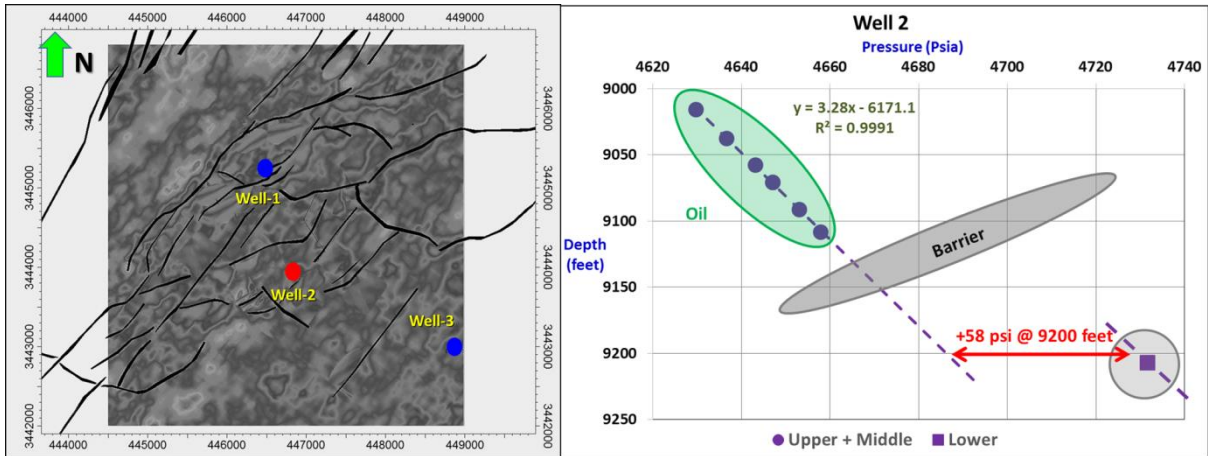
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This well was drilled in the central part of the field with the aim of crossing all the reservoir sections for collecting useful information, and to acquire pressure gradients in the desired area. The location of the concerned wells with the MDT records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

239

240

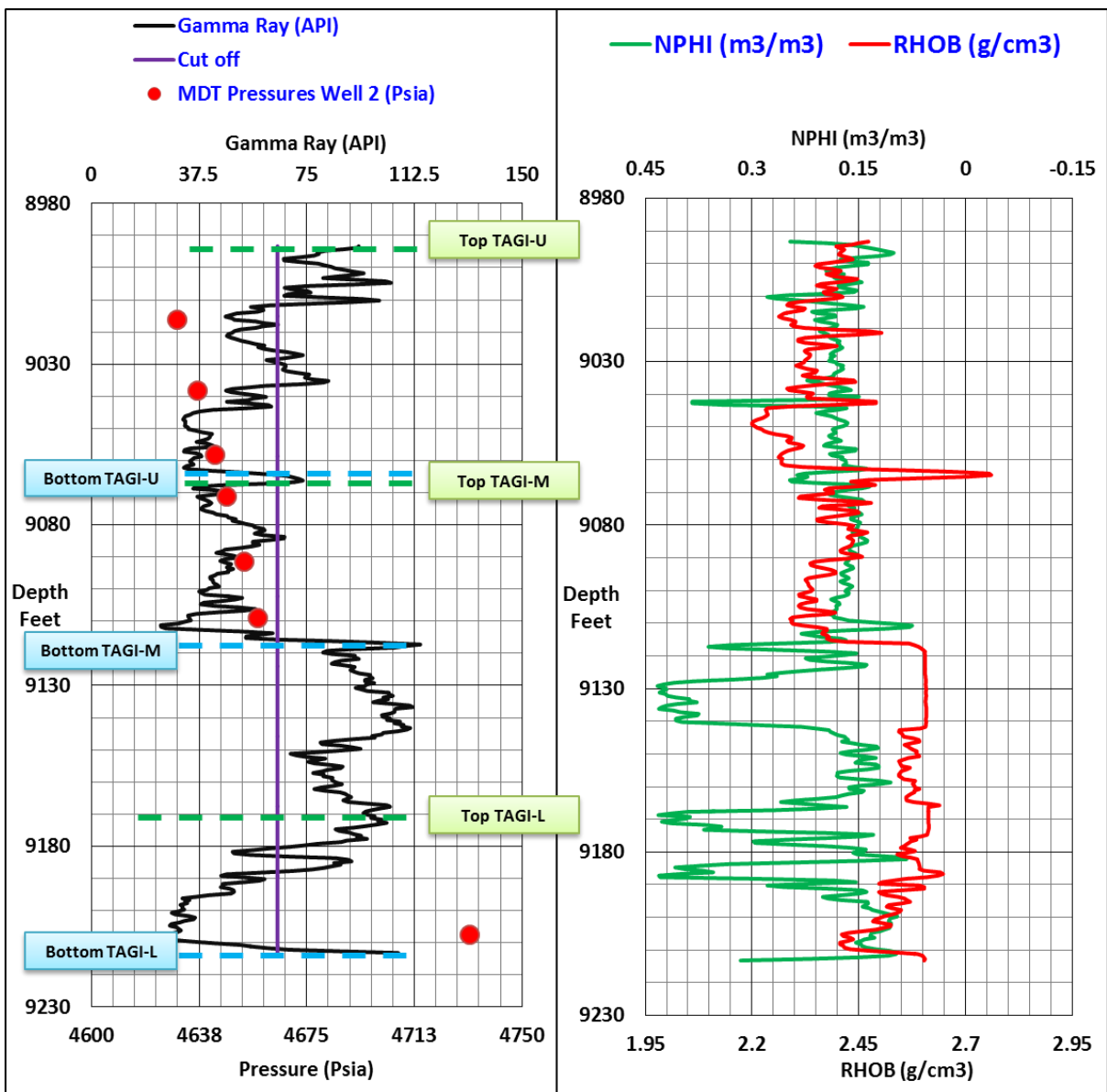
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242

243

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



244

245

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

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

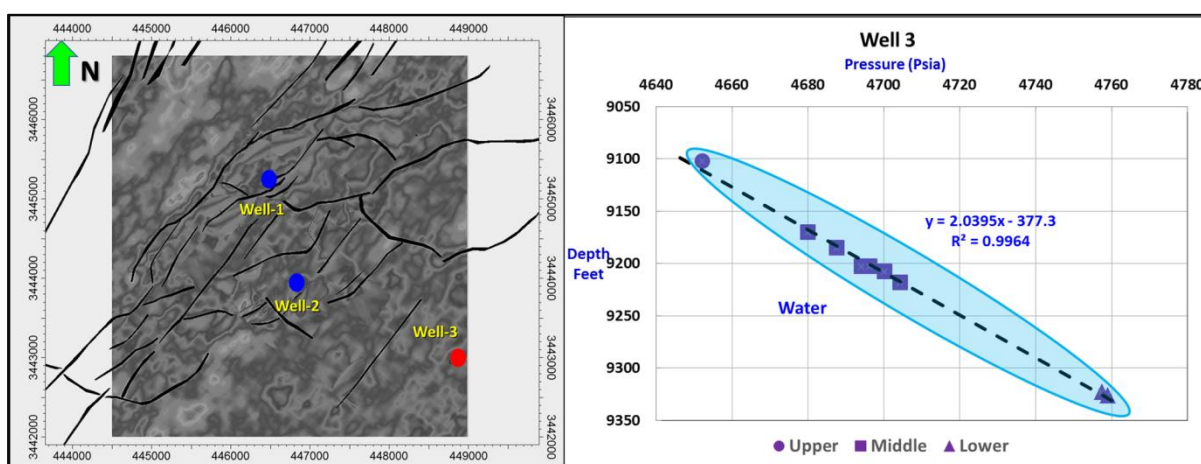
255 An identical gradient has been identified in the upper and middle reservoir sections (figure 5). It means
 256 that these upper and middle reservoirs can be treated as in dynamic communication. Assuming that, the
 257 same type of reservoir fluid was presented in the TAGI-L. Additionally and according to the gradient
 258 profiles passing through the points recorded in the TAGI U + M and the TAGI-L at depth -9200 feet, a
 259 difference of 58 Psi was observed between the Upper-Middle and Lower reservoir sections (figure 4).
 260 This distinction can be obviously related to the presence of a likely lithologic barrier between the two
 261 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	-	-	-	-	-

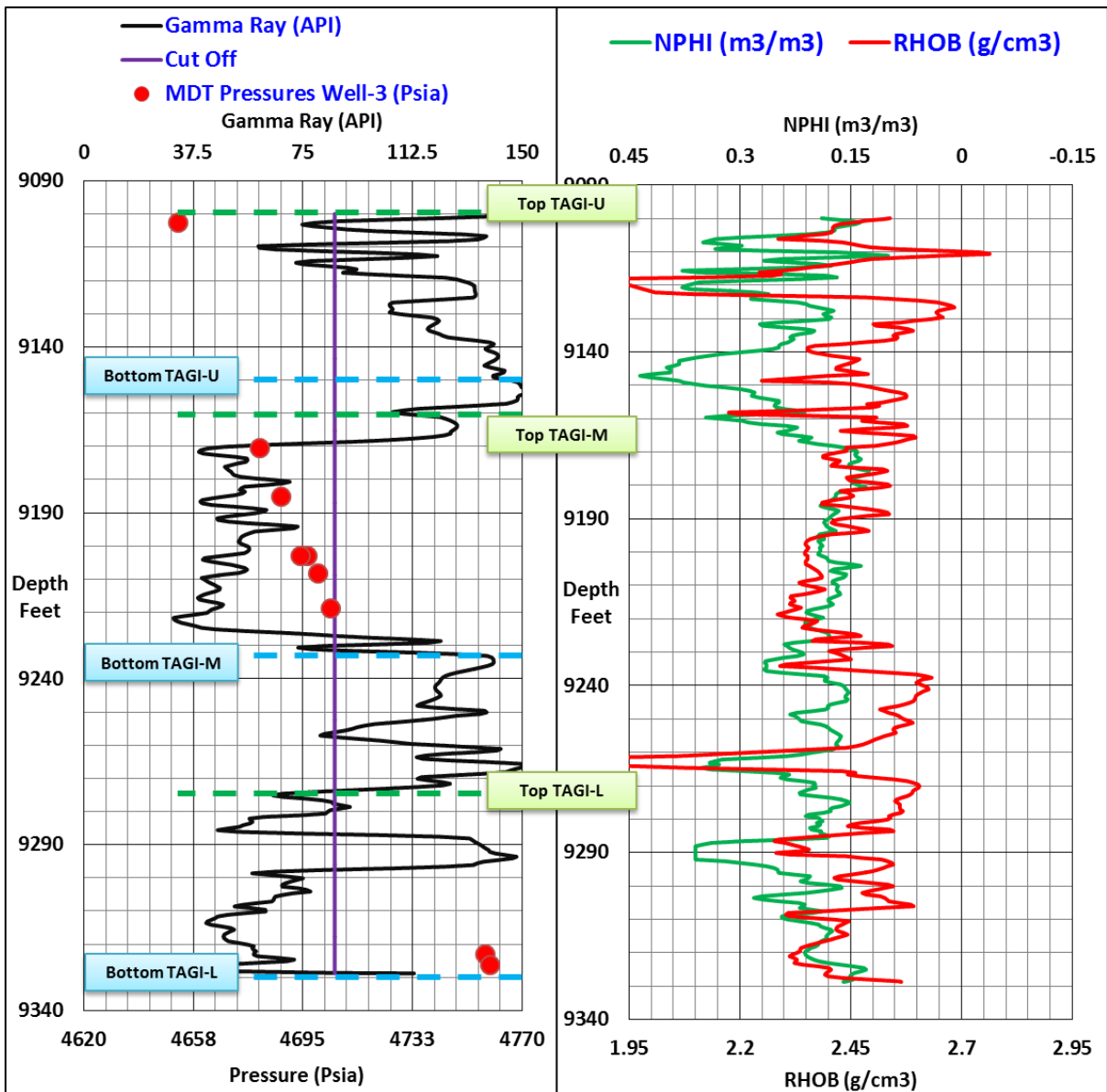
262 Table 3: Pressure gradients and fluid densities interpreted for the well-2

263 **3) WELL-3**

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



268
 269 Figure 7: Well location and pressure reordered from formation pressure tester (MDT) for well-3 with
 270 focus on water setting level



271

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

273 Regarding the figure 7, the formation pressure tester analysis (F.P.T.A.) shows the same pressure
 274 gradient profile for the upper, middle and lower reservoir sections. The implication of the gamma ray
 275 log is indicator of a stratigraphic barrier between these reservoir levels (figure 8). This statement can
 276 be, in terms of lithology, a stratigraphic barriers being revealed using well logs, Implication of pressure
 277 gradients which is the same, essentially in the TAGI-M and TAGI-L, is revealing that the three reservoir
 278 levels have been saturated by the same fluid type, a communication path is probable. Thus, the
 279 stratigraphic barrier is discontinuous or disjointed. The recorded pressure gradient in this well is about
 280 0.51 psi/ft. Similar value is corresponding to water fluid in table 4. Thus, this is revealing that the drilled
 281 borehole reservoir is a water fluid type. Depending on the location of the aquifer zone in this considered
 282 borehole, recommended is to use its own specific data information for establishing the free water level
 283 (F.W.L.) and its extend.

284

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

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

286 **B. Fluid Type (PVT) Regions Identification**

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

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

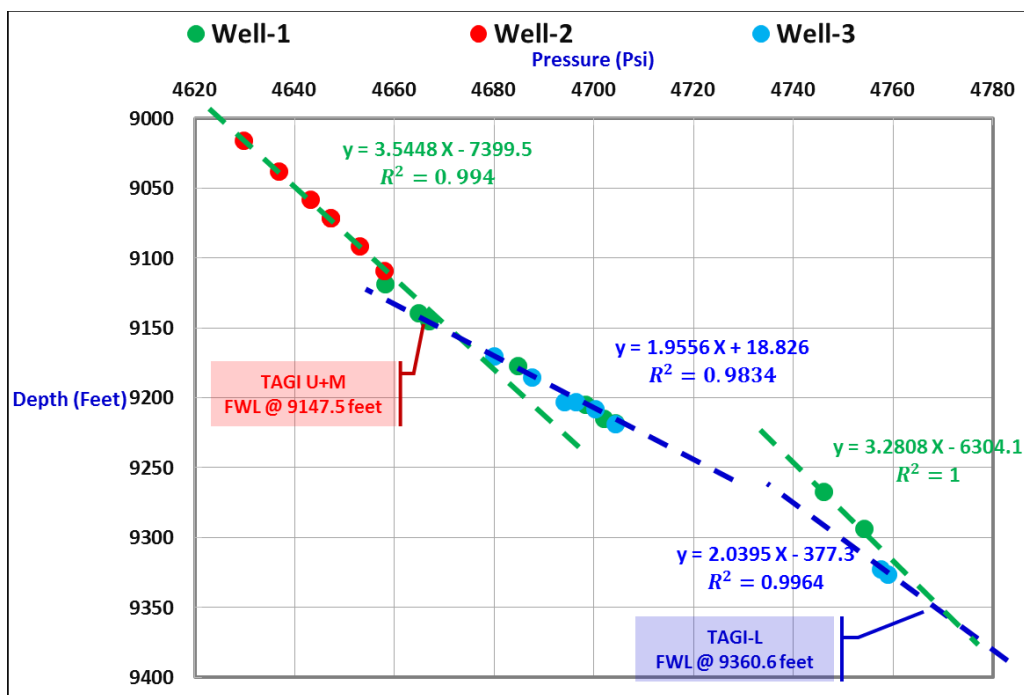
Wells	Level	Gradient (psi/feet)	Fluid Density (lb/gal)	Fluid Density (kg/m3)	Fluid Density (kg/l)	Fluid Type
Well-1	TAGI-U	0.34	6.53846	783.48048	0.78	Oil
Well-1	TAGI-M	0.47	9.03846	1083.04655	1.08	Water
Well-1	TAGI-L	0.3	5.76923	691.30631	0.69	Oil
Well-2	TAGI-U	0.3	5.76923	691.30631	0.69	Oil
Well-2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

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

303 **C. Free Water Level and Reference Pressure Determination**

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

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



320

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

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

323 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

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

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

330 Similar graphical results have allowed the estimation of the initial pressure for each reservoir layer
331 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

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

333 V. CONCLUSION

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

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

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

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

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353 VII. CONFLICT OF INTEREST STATEMENT

354 The authors have no conflict of interest to report.

355 VIII. REFERENCES

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452

453 **IX. APPENDIX**

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

454 Table showing the quality control of MDT pressure records in the exploration wells