ADVANCE FLUID TYPING AND PORE ESTIMATION USING NMR LOGGING TECHNIQUE IN MEHSANA REGION OF CAMBAY BASIN

A DISSERTATION

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Abstract

Fluid typing method has extreme importance in the petroleum industry for better understanding of reservoir and its production. The type and mobility of the fluids vary with condition of reservoir with respect the depth and exposure to pressure and temperature. For better production and economic benefits fluid typing is essential. The other major challenge is the large uncertainty in estimating porosity using conventional methods in sequence of silt laminations within shale. Pay zone delineation becomes extremely difficult due to low contrast between pay and non-pay zones in conventional logs. In this work, NMR log is used for characterizing and quantifying fluid properties. With the help of T2 distribution curve, selection of profitable zone became easy as it helped in identifying type of pores and the fluids present of the specific depth with the fluid content. 2DFC-T2D mapping help in estimating the presence of different fluids at each depth and also the bounding of the fluid in different type of pores whether clay bound, capillary bound or free fluid. Integrating conventional logs with NMR helped to predict the impurities like thinly laminated slit, ore minerals like siderite formed by the process of sulphate reduction. At last, the prospective zones are also identified for production of oil.

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CHAPTER 1. INTRODUCTION

It is often difficult to extract all kind of information from the well with the help of conventional logging tools. Therefore an increased demand by loggers to deploy advanced logging technique such as with electromagnetic, ultrasonic and magnetic transducers to obtain more nuances and its detail of the subsurface processes. One of such advanced logging technique is Nuclear Magnetic Resonance (NMR) logging.

The Cambay Basin formation is complex because of the presence of heavy mineral and different type of clays and therefore became very difficult for the petroleum engineers and petrophysicists characterizing it using conventional tools of formation evaluation. Existing study (Ajay Kumar et al, 2015) reveals that Cambay reservoir possesses laminated silt and these laminations are replaced by siderite. Presence of heavy mineral in the petroleum basin area affects the measurement in logging tools such as, density, neutron, and sonic tools and therefore makes it difficult to obtain correct estimates of porosity and hydrocarbon content. Similarly, there are multiple challenges with shales of Cambay Basin due to its low resistivity pay zones. The reason behind the complexities are, huge uncertainty in estimation of porosity whether total or effective using conventional methods of logging. The considered pay zones are not receptive to conventional logging techniques. There is also a problem of no contrast between the values of resistivity of pay zones and shales. Use of NMR logging tool then becomes very important as it is only sensitive to the fluid and its properties (type and distribution) and its interaction with the surrounding rocks. For the reasons, it becomes difficult to estimate the extract presence of hydrocarbon in the respective pay zones.

1.1. Motivation

NMR have been proved for enhancing more value to understanding Cambay shale reservoir and fluid within it. As it responds to hydrogen nuclei that is part of fluids present in the reservoir, make it extremely helpful in evaluation. In this dissertation work, I used 2D NMR fluid typing analysis which is based on different NMR relaxation times and diffusivity of different fluids. I also derive the information of clay and capillary bound fluid and free fluid with the help of T2 distribution graph. The last objective is to find the porosity of the reservoir which help in concluding estimate reservoir in further studies.

In this study, my objective is to find out the presence of hydrocarbon or other fluids like brine in the formation using the NMR logging method. This method helps in differentiating the hydrocarbon into its representative class such as, light oil,heavy oil, water or the gaseous form. Relaxation time of fluid only liked to its surrounding it the chief factor for accurate prediction of the fluid classes and is considered a more accurate method than other conventional methods. Therefore, in this thesis, I set out the following objectives to adequately characterize the formation laden with heavy minerals and shales for assist in keeping it as an economical play:

1.2. Objectives

My objective for this thesis are:.

1. Determination of fluid type,
2. Determination of fluid movement,
3. Estimation of porosity.

CHAPTER 2. LITERATURE REVIEW

Nuclear Magnetic Resonance (NMR) logging is a subcategory of electromagnetic logging. It works on the physical phenomenon used in MRI (Magnetic resonance imaging) technique, in which magnetic field is generated by a permanent magnet that magnetizes the materials in the formation.

NMR logging, measures the induced magnetic moment of hydrogen nuclei of various fluid present in the pores of the reservoir rock or any porous media. It is different from the conventional logging method's measurements which are affected by the matrix of the rock and fluid properties, whereas NMR responds to fluid composition, viscosity, volume and distribution. That's why NMR is also known as **true fluid-logging device.** NMR sequence measurement follows three important steps, those are, **and alignment of proton**, **spin-tipping and its precession** and **repeated dephasing and refocusing of it.**

In proton alignment, static or constant magnetic field, symbolized as Bo is applied on randomly oriented magnetic nucleus. Due to the magnetic field Bo, a torque is acted on the nuclear spin axis which causes precession of nucleus around Bo with precessional frequency, called the **Larmor frequency**. Larmor frequency is directly proportional to magnitude of static magnetic field of the given nucleus. Large numbers of spinning protons are aligned under the magnetic field Bo, more in parallel to Bo then anti parallel.

In spin-tipping, new or oscillating magnetic field B1 is aligned with the same frequency of Larmor frequency. When this B1 field is applied aligned protons are tipped through its direction. On the macroscopic level, due to the resonance the tipping of the magnetization, which precessed about Bo at the given Larmor frequency.

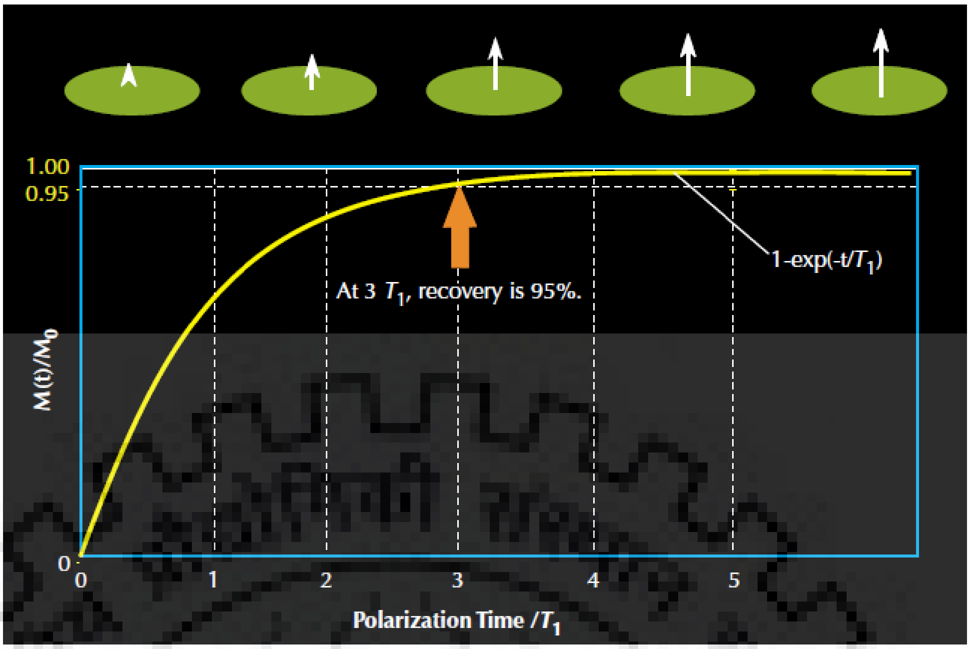


Figure 1-T1-relaxation (polarization) curves reflects the degree of alignment of proton, or magnetization, as a function of time that a population of proton which is exposed to an external magnetic field. (Source: Coates G.R. et al, 1999)

In dephasing, the protons will precess or directed around the current direction of B1. This alignment is measured by an antenna inside the Nuclear Magnetic Resonance tool. However, as known that B0 is not even perfectly homogenous and that's why the protons will not or do not all precess exactly at the same frequency. Moderately they elude synchronization (as known as dephasing) and the upcoming decaying signal is measured. The symbolization for the decay time is called T2 (this is not likely a formation property) and this is comparable to the tipping pulse span length.

This decay signal is also referred to as free induction decay (FID).This decay is usually exponential. The FID time constant (T2) is as comparable very short—around few tens of microseconds. The FID is happened by magnetic-field inhomogeneities that are due to the magnetic field gradient and to certain molecular processes that occur in the measured material. Because of the inhomogeneities in the B0 field, protons at different locations will precess with different Larmor frequencies, thereby producing this very rapid decay.

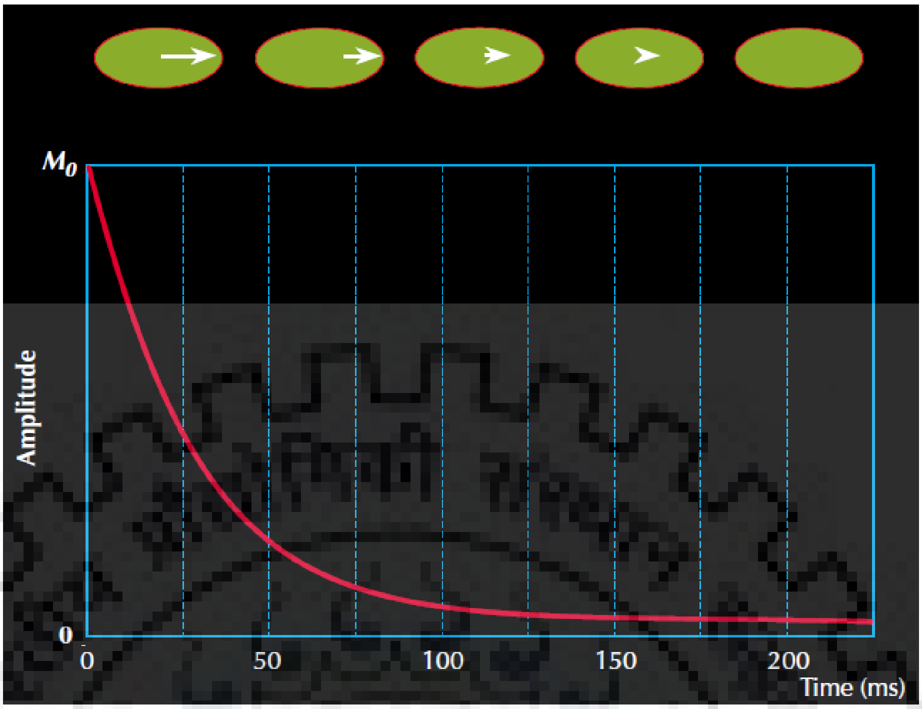


Figure 2- The amplitudes of the decaying spin echoes yield an exponentially decaying curve with time constant T2. (Source: Coates G.R. et al, 1999)

In refocusing, the protons (all precession at a slightly different frequency) can be refocused by a new pulse, which is 180 degrees oriented to the original spin-tipping pulse and also twice as long. The proton magnetization vectors in the transverse planes can be re-phased when a 180° B1 pulse is applied. As the protons rephase, they generate a new signal in the antenna – called a spin-echo. The spin echo decays again on the rate of the FID. However, the 180-degree pulses are applied repeatedly – typically several hundred times within a single NMR measurement.

In spin-echo detection, if a transverse magnetization vector has phase angle α, then application of a 180° B1 pulse will change the phase angle to -α. In effect, the phase order of the transverse magnetization vectors is reversed, so that the slower (phase wise) vectors are ahead (phase wise) of the faster vectors. This signal is called a spin echo. If time τ transpires between the application of the 90° B1 pulse and the 180° B1 pulse, then the same time τ will transpire between the application of the 180° B1 pulse and the peak of the spin echo. Rephasing time is equal to dephasing time, and the spin echo peak occurs at 2τ (or TE).

CHAPTER 3. METHODS AND MATERIALS

3.1. Method Involved

The techniques that is used in this work is based on T1 relaxation and/or diffusivity contrast for review on NMR properties of hydrocarbons and NMR hydrocarbon-typing techniques and other one is qualitative forward modelling of oil and gas effects on T2 distributions under different conditions.

T1 relaxation term is given for bulk fluid relaxation and T2 is of bulk relaxation as well as diffusion term. Due to differences in T1, T2 and D among these fluids lead the foundation for NMR fluid typing. Two methods of hydrocarbon typing which is going to be used are: dual-TW and dual-TE. The dual-TW method is based on the T1 contrast between brine and light hydrocarbons. The dual-TE method is based on the diffusivity difference between water and medium viscosity oil or can be said as between liquid and gas.

Fluid	T_1 (ms)	T_2 (ms)	Typical T_1/T_2	HI	η (cp)	$D_0 \times 10^{-5}$ (cm^2/s)
Brine	1 - 500	1 - 500	2	1	0.2 - 0.8	1.8 - 7
Oil	3,000 - 4,000	300 - 1,000	4	1	0.2 - 1,000	0.0015 - 7.6
Gas	4,000 - 5,000	30 - 60	80	0.2 - 0.4	0.011 - 0.014 methane	80 - 100

Table 1- NMR Properties of Reservoir Fluids. (Source: Coates G.R. et al, 1999)

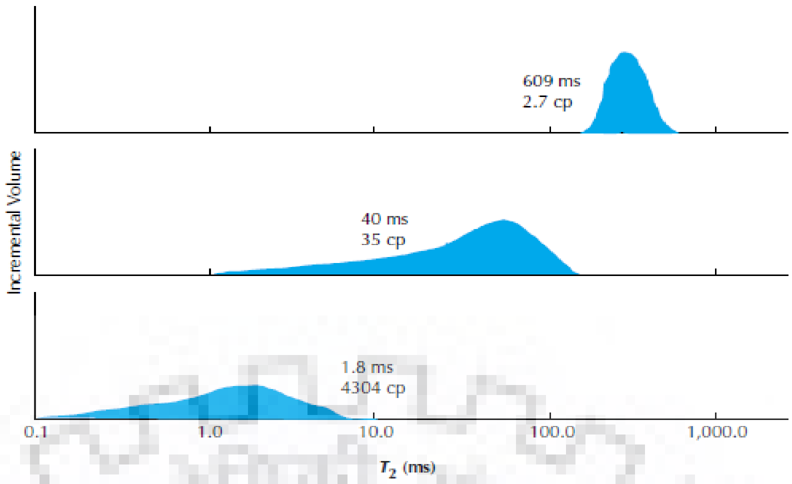


Figure 3- T2 of crude oil varies with viscosity. For light oil (top), medium viscosity in middle and heavier crude oil in the last part of the figure. (Source: Coates G.R. et al, 1999)

3.1.1. T1 Relaxation Contrast

As from the above given table, it can easily be concluded that gas and oil each have T1 relaxation times much longer than that of brine. For full polarization the time TW relaxation is longer for hydrocarbon than for water.

For the short TW,

$$M_{TW_{short}}(t)=\sum M(0_i)\left(1-e^{-TW_{short}/T_{1wi}}\right)e^{-t/T_{2wi}}$$
$$+M_{oil}\left(1-e^{-TW_{short}/T_{1oil}}\right)e^{-t/T_{2oil}}+M_{gas}\left(1-e^{-TW_{short}/T_{1gas}}\right)e^{-t/T_{2gas}}$$

For the long TW,

$$M_{TW_{long}}(t)=\sum M(0_i)\left(1-e^{-TW_{long}/T_{1wi}}\right)e^{-t/T_{2wi}}$$
$$+M_{oil}\left(1-e^{-TW_{long}/T_{1oil}}\right)e^{-t/T_{2oil}}+M_{gas}\left(1-e^{-TW_{long}/T_{1gas}}\right)e^{-t/T_{2gas}}$$

where, T_{1wi} and T_{2wi} are the T_1 and T_2 of water in the i^{th} bin respectively.

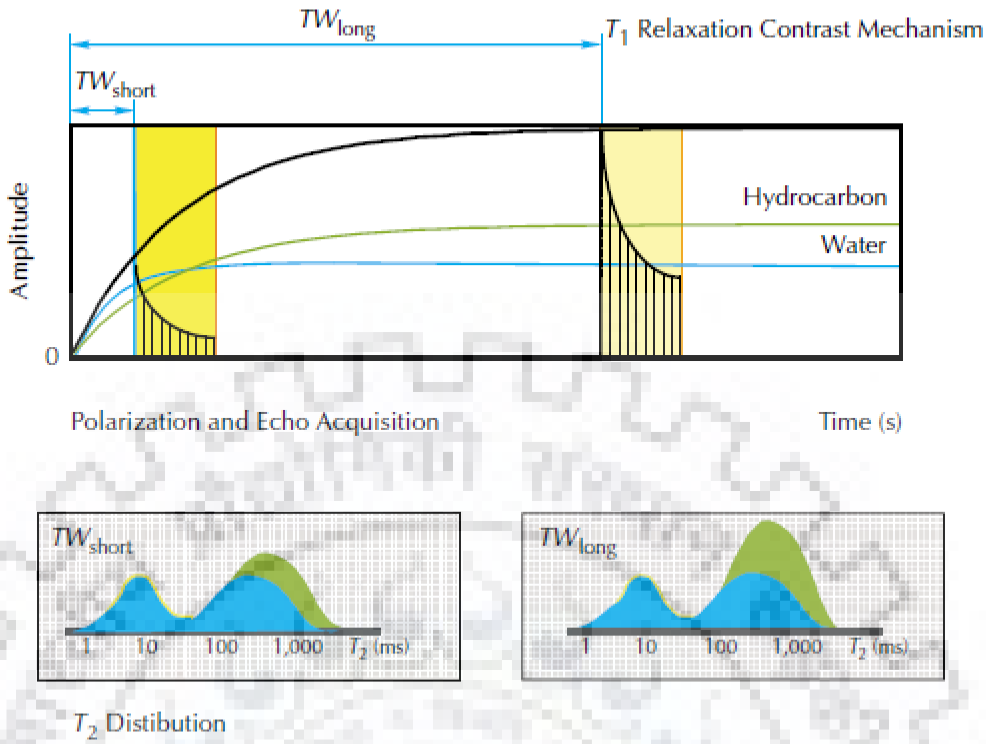


Figure 4- In the dual-TW measurement, only water can fully polarize during TW short, while both water and hydrocarbons can fully polarize during TW long. (Source: Coates G.R. et al, 1999)

3.1.2. Diffusivity Contrast

T2diffusion depends on molecular diffusion coefficient (D), field strength gradient (G) and inter-echo spacing used in CPMG sequence. If brine, medium and high viscous oil is taken, Dgas is much greater than Dw and Dw is much greater than Doil. Therefore, T2diffusion will be very different among these fluids, and difference of NMR measurement made with different TE help in identification of these fluids, Dual-TE measurements using two TE values and these are TEshort and TElong.

For the short *TE*,

$$M_{TE_{short}}(t)=\sum M(0_i)\left(1-e^{-TW/T_{1wi}}\right)e^{-t\left(\frac{1}{T_{2w}}+\rho\frac{S}{V}+D_w\frac{(\gamma G\,TE_{short})^2}{12}\right)}$$
$$+M_{oil}\left(1-e^{-TW/T_{1oil}}\right)e^{-t\left(\frac{1}{T_{2oil}}+D_{oil}\frac{(\gamma G\,TE_{short})^2}{12}\right)}+M_{gas}\left(1-e^{-TW/T_{1gas}}\right)e^{-t\left(D_{gas}\frac{(\gamma G\,TE_{short})^2}{12}\right)}$$

When $TW >> 3\text{xmax}\,(T_{1w}, T_{1oil}, T_{1gas})$,

$$M_{TE_{short}}(t)=\sum M(0_i)e^{-t\left(\frac{1}{T_{2w}}+\rho\frac{S}{V}+D_w\frac{(\gamma G\,TE_{short})^2}{12}\right)}$$
$$+M_{oil}\,e^{-t\left(\frac{1}{T_{2oil}}+D_{oil}\frac{(\gamma G\,TE_{short})^2}{12}\right)}+M_{gas}\,e^{-t\left(D_{gas}\frac{(\gamma G\,TE_{short})^2}{12}\right)}$$

For the long *TE*,

$$M_{TE_{long}}(t)=\sum M(0_i)\left(1-e^{-TW/T_{1wi}}\right)e^{-t\left(\frac{1}{T_{2w}}+\rho\frac{S}{V}+D_w\frac{(\gamma G\,TE_{long})^2}{12}\right)}$$
$$+M_{oil}\left(1-e^{-TW/T_{1oil}}\right)e^{-t\left(\frac{1}{T_{2oil}}+D_{oil}\frac{(\gamma G\,TE_{long})^2}{12}\right)}+M_{gas}\left(1-e^{-TW/T_{1gas}}\right)e^{-t\left(D_{gas}\frac{(\gamma G\,TE_{long})^2}{12}\right)}$$

When $TW >> 3\text{xmax}(T_{1w}, T_{1oil}, T_{1gas})$,

$$M_{TE_{long}}(t)=\sum M(0_i)e^{-t\left(\frac{1}{T_{2w}}+\rho\frac{S}{V}+D_W\frac{(\gamma G\,TE_{long})^2}{12}\right)}$$
$$+M_{oil}\,e^{-t\left(\frac{1}{T_{2oil}}+D_{oil}\frac{(\gamma G\,TE_{long})^2}{12}\right)}+M_{gas}\,e^{-t\left(D_{gas}\frac{(\gamma G\,TE_{long})^2}{12}\right)}$$

Different effects of oil on T2 distributions vary with the fluids present in the pores. The sharp boundaries between the various components do not imply sharp boundaries between corresponding decay septra. Using short TE and long TW for measuring echo train, water gives board T2 distribution, while T2 value for light oil will have narrow distribution. There will be little contrast between the diffusion coefficients of water and light oil but the T1 value for light oil and pore water is different, so it can be used between two fluids for detection. As there is a large contrast in the value of T1 between water and light oil, the signals of water will be disappears when the TW short and TW long are subtracted from each other. The resultant spectrum will be only the light-oil signal. It is necessary to note if oil based mud is used, a signal from the mud filtrate will appear on the T2 distribution.

3.1.3. 2-Dimensional Fluid Characterization (2DFC-T2D) Interpretation Method

2DFC-T2D (Two Dimensional Fluid Characterization T2D) is a standalone NMR processing model designed to use when evaluating NMR well data with 2 dimensional (2D) inversions of simultaneous multi-echo spacing T2 data. The primary application of 2DFC-T2D is for oil identification and quantification in either water-based or oil-based mud systems. The resulting outputs can be used with conventional logs to enhance and improve the log interpretation of oil and gas (methane) bearing reservoirs.

The 2DFC-T2D model neither assumes, nor relies on knowing, the nature of hydrocarbons present in the formation in most instances. However, the interpretation results are based on options available for selecting the drilling mud system for the well to be analysed. Selecting oil-based mud (OBM) or water-based mud (WBM) will determine how the 2D map partitions are initialized to distinguish individual fluid types. Specific activation sets are recommended to acquire the appropriate NMR datasets for applying 2DFC-T2D processing. These activation sets are identified within MRIL Prime and MTE (Multiple Te).

These activation sets provide for a long wait time to achieve full polarization of all echo spacing and use a minimum of four different echo spacing with partial recovery activation.

The primary output from 2DFC-T2D is a 2D map of T2Intrinsic and Diffusion distributions; petrophysical quantities are extracted from these distributions. These quantities include gas, oil, heavy oil, moveable water, and bound fluid volumes for WBM environments, and OBM filtrate volume for OBM environments.

T2Intrinsic and Diffusion are simultaneously computed during processing. T2Intrinsic has no diffusion component and is similar to T1. In this report, “T2” is used to refer to “T2Intrinsic”. Individual T2 and Diffusion distributions for each fluid type are also computed from the 2D map and displayed as outputs.

2DFC-T2D is an analysis technique that only uses the MRIL data. The technique is optimized to identify methane gas and differentiate gas from liquids (either oil or water). Because this technique only uses MRIL data and the MRIL is a relatively shallow depth of investigation measurement, the fluid volumes and saturations determined are representative of the flushed zone. If there is mud filtrate invasion, this will affect the fluid volumes determined from this technique.

Processing appropriate activation sets for 2D NMR produces a 2D map that represents the simultaneous inversion of multiple echo train acquisition with respect to two NMR parameters, normally T2 or T1, and Diffusion.

Figure 5 illustrates the basic organization of the 2D T2-Diffusion map with the lines organized for gas, oil, and water. Water is shown on these maps along the blue line because its diffusivity value is quite high and its relaxation rate will depend on the pore size in which it resides. Water in smaller pores will display at shorter T2Intrinsic times, and water in larger pores will display at longer T2Intrinsic times. In vuggy carbonate scenarios, moveable water may have a very long T2Intrinsic time; consequently, the water signal will be located on the right side of the water line with a very long T2Intrinsic value. Micro and bound fluids often display a large range of diffusion on the map because a larger diffusion uncertainty exists at very short T2Intrinsic values. The position of this water line is primarily a function of temperature.

Oil will display on the maps along the green line because both its diffusivity value and its T2Intrinsic relaxation rate are inversely proportional to the viscosity of the oil. The formation is assumed to be water-wet, and the oil exhibits bulk properties with no surface relaxation effect. Viscous oil will display on the oil line with a short T2Intrinsic value and low diffusion value. Light oil will display on the oil line with a longer T2Intrinsic value and higher diffusion value. Gas will display on the maps along the red line because its diffusivity value is very high, and it will have a long T2Intrinsic value. The formation is assumed to be water-wet, and the gas exhibits bulk properties with no surface relaxation effect.

Several fluid and reservoir effects may also be inferred from the 2D maps, such as gas/oil ratio (GOR), wettability, and restricted diffusion. Restricted diffusion may occur when the reservoir pore size is very small, but this is relatively uncommon.

The effect of restricted diffusion is to reduce the measured diffusion of the fluids, in which water may display below the blue water line at a lower diffusion value than predicted. Internal gradients within rocks occur when paramagnetic or ferromagnetic minerals are present and in contact with the pore fluid. The most common paramagnetic minerals include chlorite, siderite, and pyrite, all containing iron. Paramagnetic or ferromagnetic minerals that are within the rock matrix but not in contact with the pore fluid will not produce an internal gradient effect. The internal gradients increase the effective diffusion such that fluid may have higher measured diffusion values; consequently, water may display above the blue water line. The true measure of internal gradients is performed in a laboratory setting with a NMR spectrometer. Internal gradients also shorten T2Apparent; however, because 2DFC-T2D computes T2Intrinsic, only an increase of diffusion is apparent.

Reservoirs that are mixed wet can shorten the T2Intrinsic of the oil signal, such that an oil signal displays on the left side of the green dead oil line. This may not occur in all cases, however, and the true measure of mixed wettability or oil-wet condition is performed in a laboratory setting. Oils that contain gas in solution become lighter as their viscosity reduces; they display as oil signals with a long T2Intrinsic and higher diffusion values along or above the green oil line. As the GOR increases, these very light oil signals may often display at long T2Intrinsic values between the gas region and green oil line.

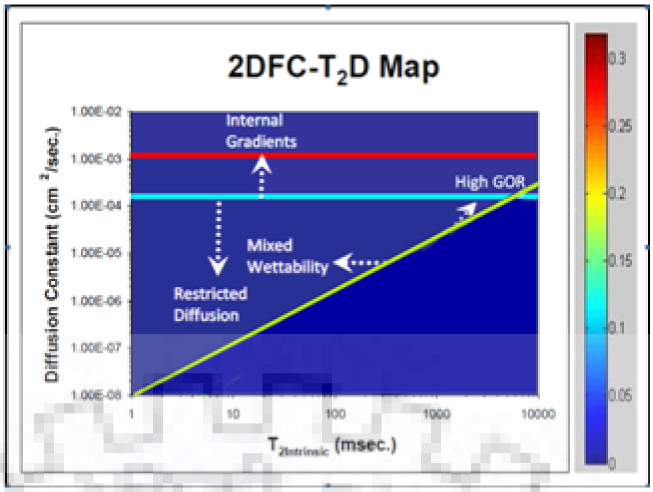


Figure 5: 2D T2-Diffusion map organization and format

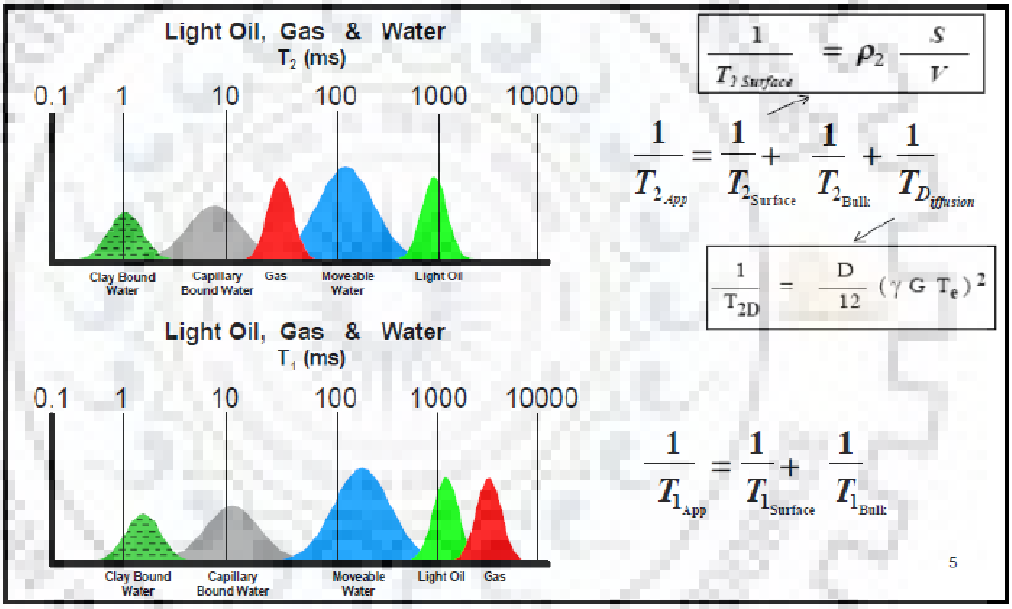


Fig. 6. Time Domain Analysis - TDA Light Hydrocarbon < 2cp & Gas and T1 and T2 fluids. (Source: Coates G.R. et al, 1999)

3.2. Study Area

The Cambay rift Basin is one of the rich petroleum province of India. It is a narrow elongated rift garden. It is extended from Surat in the South to Sanchor in the north. The north part of the basin is narrow, but tectonically continues beyond Sanchor to pass into the Barmer Basin of Rajasthan.

The Cambay Basin is a narrow elongated rift basin having Pre-Cambrian basement consists of igneous and metamorphic rocks. It have two major extension one in the southern-western extension of the Aravalli-Delhi Orogenic belt and other one in ENE-WSW trending Satpura Orogenic belt extends under the offshore in the southern part of the basin.

The trap sediments are characterised by an ill sorted and high energy trap derived materials.Subsidence of euxinic black shales with subordinate coarser clastics. Rapid phase with oscillating conditions of deposition and development of deltaic sequences in the entire basin in the middle Eocene and in the late Eocene, there was regional southward tilt of the entire rift basin and it is marked by a regional marine transgression extending far to the north upto Sanchor basin.

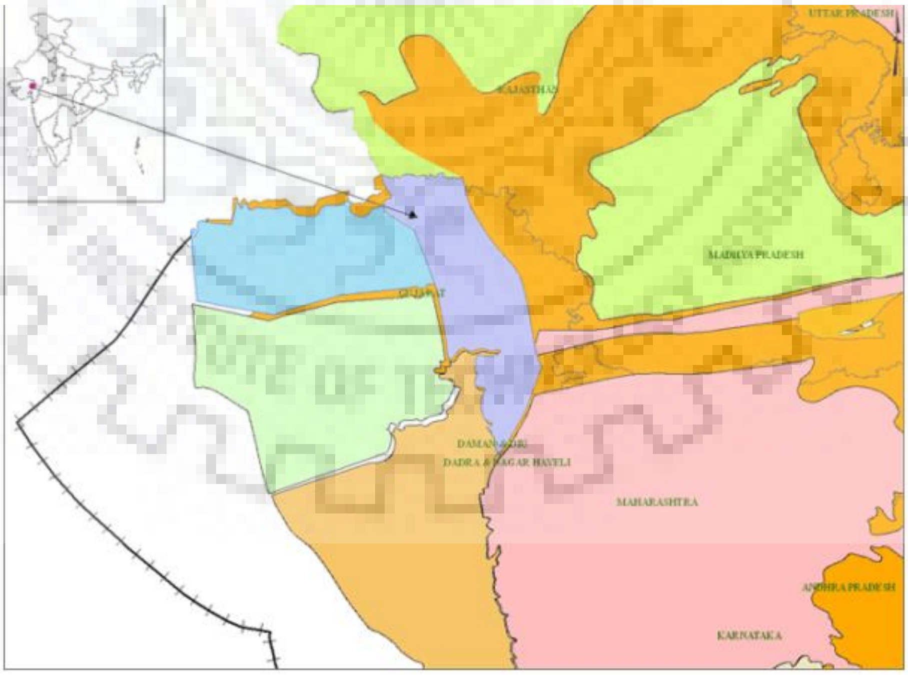


Figure 7 – Cambay Basin. (Source: ndrdgh.gov.in)

Mehsana-Ahmedabad Block

Mehsana-Ahmedabad block surrounded by Khari River from North and Vatrak River from South. Its major lineament trends in NNW-SSE direction with the intra graben horst. The Mehsana horst divides the basin into two depressions as eastern and western. The eastern barrier part lies in continuity with Tarapur-Cambay block and Kalol formation.

Tarapur Formation

It is deposited during period of marine transgression, characterized by intercalation of shale, claystone, clay and few sandstone beds. The age of Tarapur formation is of mid Eocene to early Oligocene.

Babaguru Formation

This formation is represented by ferruginous, current bedded sandstones, conglomerates and grey clays. The sand grains and pebbles are mostly of quartz, agate and chalcedony. The formation is mostly devoid of fauna including *Cicatricosisporites venustus, Megnastriatites cauveriensis and Polypodisporites formosus.* The age of this formation is Lower Miocene.

Kand Formation

The Babaguru formation is overlain by Kand formation. The outcrops of this formation consist dominantly of grey clay and claystone. The formation is comprises of interlayering of grey to brown, soft clays and claystones and thin bands of white coarse grained sandstones having thickness of about 200m. The age of this formation is of Lower Miocene to Middle Miocene.

Structural Setting

The major events of Gujarat are confined from Mesozoic to Cenozoic Era. The geological evolution started with the breaking up of Gondwanaland and drifting of Indian plate towards northward.

The Narmada-Son lineament divides Indian shield into southern peninsular block and the northern foreland block. A series of parallel extension faults opened up the Cambay basin and the Western Continental Shelf. The basin of Cambay hs rifted during Early Cretaceous and follow the Dharwar and Satpura trends.

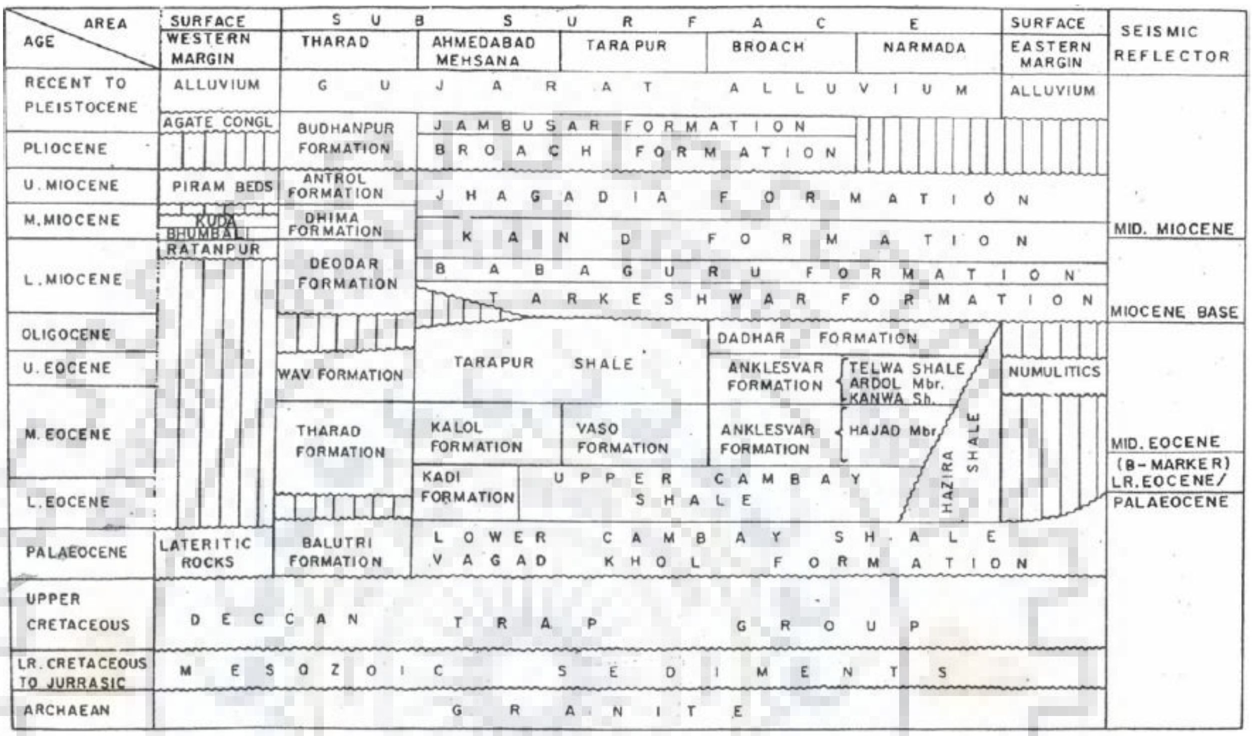


Figure. 8 - Cambay basin stratigraphy (Source: Sastry et al., 1984)

3.3 Data Availability

The NMR data provided by the HLS Asia Limited belong to a well of Mehsana Area in Cambay basin which is under the supervision of PAN India.

The other conventional logs (Gamma-Ray, SP, Bit size, Caliper, Density-Neutron and Resistivity) data are also provided by the HLS Asia Limited.

3.4. Well Information and Pre-Job Planning

3.4.1. Well Information

Table-2: Basic Information	
Bit Size	8.5 in
Mud Type	WBM
Mud Weight	10.2 ppg
BHT	160 DEGF
Tool Type	MRIL-Prime
MRIL Logging Activation Mud Resistivity @ Temp	D9TE512 .65 OHM.M @ 95.84 DEGF
Mud Filtrate Resistivity @ Temp Mud Cake Resistivity @ Temp	.60 OHM.M @ 66.74 DEGF .74 OHM.M @ 70.88 DEGF
Logging speed	0.7 m/min
Logging Interval	800-900 M

MRILCuttoff used for processing	
T2 Clay & BVI Cutoff	7 & 33 MS and 3 & 16 MS for Trap wash

3.4.2. MRIL Pre-Job Planning

A 2D-MRIL-Planner is a program which contained several constraints limiting capability to model Halliburton's current and future range of NMR wireline and Perforating and Sperry Drilling applications. It helps in improving the capability for modeling a large range of reservoirs and fluids. It also have availability of resulting logging speeds for selected vertical resolution.

It help in measuring the speed at which the NMR tool run into the depth of the Earth. In the given data the NMR tool run with a constant speed.

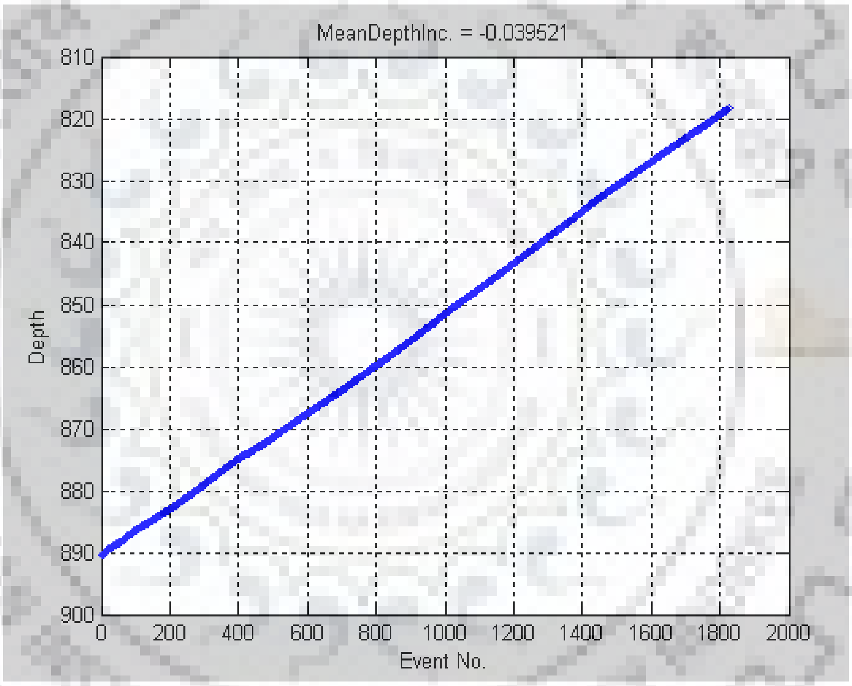


Figure.9 – Cross plot of Event number and Depth

General Info Tab

The first tab which is opened is the "general info tab" in which the user have to enter information regarding customer, well, MRIL equipment and logging objectives.

In the "Customer Information" tab, the user have to add all the basic information of the customer like its name, address, email and phone.

The “Well Information” tab contains information of well name, its location, total depth, pressure-temperature conditions, mud properties, casing and the logging interval.
The logging objective allows the user to document the customer objective for logging NMR services in the particular well.

The last tab of “MRIL Equipment” have information of type of NMR sensor intended for logging is selected. The type of sensors are MRIL-Prime, slim MRIL-Prime, MRIL-XL, MRIL-WD6 and MRIL-WD4.

Figure 10: General Info Tab

NMR Info Tab

After completing the data filling information in the General Info Tab, the user should proceed to the NMR Info Tab. Information must be entered in the blocks for the Environment, Formation, mud and fluid composition sections.

In the Environment Tab, the user enters the depth of the well by specifying the top and bottom of the interval.

In Formation Tab, user enter the rock type (sandstone/limestone etc.), its grain size and relaxivity (10 sec/um for sandstone and 3 sec/um for limestone).

In Mud Tab, user have to enter the mud type and its property of viscosity value. In Fluid composition, user have to enter the earlier now value of porosity, saturation of water, gas, oil, salinity of brine, gas GSG, oil GOR, oil GSG and oil API values.

In last, the tab of NMR tool, user have to enter tool type, activation set and process type depending upon the need and the method which user using for NMR logging.

In the figure 11, as user had added different values which affect the graph and other values of the data. Pressure input will affect the computed value of T1 and T2 position of gas (methane) line and temperature input will affect water line in the distributions and 2D maps. Similarly the borehole selection will affect the computed Depth of Investigation for the chosen Tool Type and Activation set. As my work is on the depth ranges from 800 metres to the depth of 900 metres (but I check the condition till the depth of the borehole, which is 965 metres). The value of bottom-hole temperature and pressure is 160 F and 1200 psi respectively.

In the Formation section inputs, grain size affects where water is estimated within the distributions and 2D maps. Smaller or finer grain sizes are expected to reflect small pore sizes resulting in shorter T2 and T1 values for water while larger or coarser grain sizes are expected to reflect large pore sizes resulting in longer T2 and T1 values for water. The value that I entered was provided by the HLS Asia for sandstone rock type and grain size variation from fine to medium. As the default value of relaxivity of sandstone is 10 sec/um that appear automatically in the place of relaxivity.

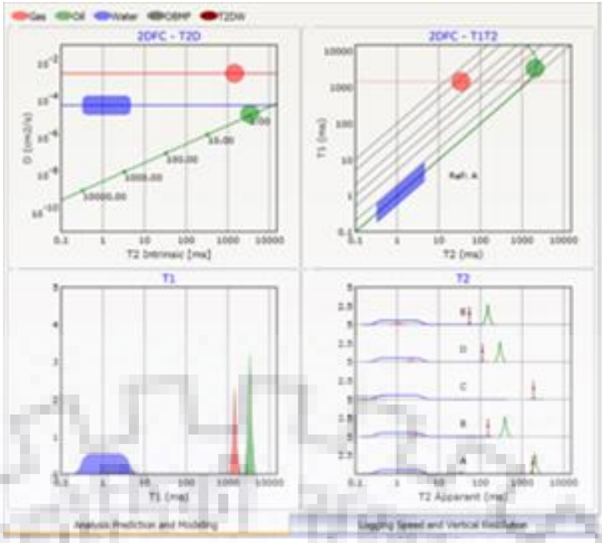


Figure 11: NMR info tab and analysis prediction and modelling tab

In mud tab, I added the mud type as water based mud (WBM) and its salinity as 7.5 in kppm NaCl.

In fluid composition, I added the values of porosity as 20 percent unit, saturations of water, oil and gas as 40%, 35% and 25% respectively. The water salinity is of value of 0.2 in kppm of NaCl. Gas GSG value is provided is equal to 0.6 and oil GOR as 400 SCF/STB. The value of oil API is of value of 40.

In the NMR tool tab, Tool Type is already mention as MRL-Prime, activation set as D9TE512 is chosen as I am working on the T2intrinsic and diffusivity graph with better resolution and the graph shown are of T1 only, T2 only, T1T2 and T2D. In the activation group the value of TW, TE, Ne, MIN RA and average gradient in Gauss/cm is produced as the result. In this activation group Tw is almost fixed and we increase or varies the Te value in multiple of first Te. With the help of this method, user can distinguish the oil and gaseous form of hydrocarbon.

The graph of 2DFC-T2D, shows the lines of water, gas and oil based on its diffusivity and T2intrinsic help in distinguish the concentration of water, gas and oil.

In the graph of 2DFC-T1T2, the axis is of T1 and T2 is given. The value of T1 and T2 of water are very low that’s the reason the position of water is in lower left corner, the value of T1 and T2 of gas is high and moderately high respectively, therefore the portion

of gas is at center-up region. The value of T1 and T2 of oil depend on its density or API, if the density is high then the oil portion will be near to the water portion and as the density decreases, the portion raises upward with increasing T1 and T2 value.
The graph of T1 shows the distinguishable portions of all three fluids.

The graph of T2 shows the water portion and variation of oil and gas with the change of value of Te, as in A where TE value is 0.9ms, it is difficult to distinguish oil and gas. As with the increase in time in the following steps, the differences between the oil and gas become easily visible.

Figure 12: Logging speed and vertical resolution tab.

This tab gives the information based on the input data, what should be the logging speed and the vertical based that used be considered while running the tool. In our case, if user/ customer wants good resolution of 4 feet then logging speed should be 2.4 feet/min or for lower resolution of 6 feet than the speed will be double and become 4.8 feet/min.

From the figure 13, I can conclude that the volume of water, oil and gas are 8%, 7% and 5% respectively from the total porosity of twenty percent, as provided by the user. The polarized volume of water oil and gas is of 7.86, 6 and 0.61 respectively with the total polarised volume of 14.47. The hydrogen index total volume of water, oil and gas are

7.86, 6.18 and 0.61 respectively with the total of 14.65. The percentage of polarized hydrogen to the total HI is 98.78 percent in the given time of the polarization or Twait.

The polarization curve help to estimate the total percent or part that is polarised in the fixed wait time by the user. As it can be seen that while fixing the wait time of 12s, all water and gas is polarized and almost all water is too polarised in that time period. From this, the user confirm the time of stay that each depth the instrument must take for best result or total polarisation. Due to which the best result can be gathered as it polarised all the hydrogen present in the fluids.

The depth of investigation of the under the condition of the well and data provided by the user is 3.51 inches at average. The depth of investigation on high side and low side will be 3.01 and 4.01 respectively. The appropriate number of echoes that required for the total polarisation is 755. The T1 time required from the given data of oil, gas and water in microsecond are 3377.24, 1450.65 and 4.48. The T2 time required from the given data of oil, gas and water in microsecond are 2039.75, 33.94, and 4.47.

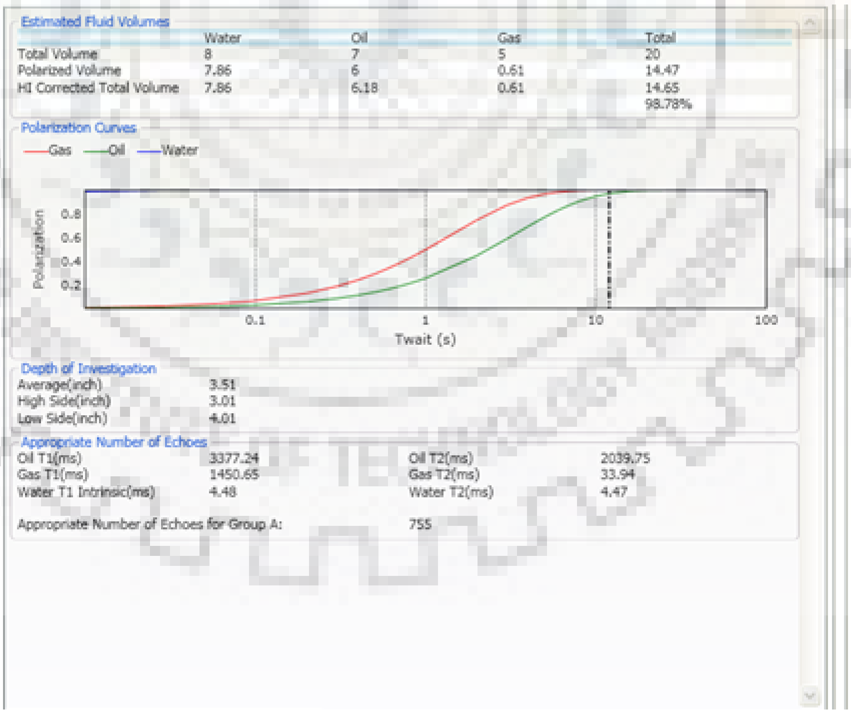


Figure 13: Determination of acquisition parameters tab.

In the figure 14, the first tab is of fluid properties. In this tab, there are the primary information of the different fluid types. The first information of temperature of water, gas, oil that is 71 degree Celsius or 160 Fahrenheit and of dead oil is 16 degree Celsius or 60 Fahrenheit. The pressure condition is of water, oil and gas is 1200 psi or 8 mega Pascal and for dead oil is 15 psi or 0.101 mega Pascal. The density can be calculated through the data provided of water, gas, oil and dead oil are 0.98, 0.05, 0.70 and 0.82 in gram per cubic centimetre respectively. The viscosity of water, oil and dead oil is 0.39, 0.79 and 4.67 poise respectively. The diffusivity of the water, gas, oil, dead oil and mud filtrate are 5.87, 302.58, 2.04, 0.29 and 5.51 respectively. The hydrogen index of water, gas, oil and dead oil with respect to dead oil are 0.98, 0.12, 0.88 and 1.00. These are the characterised value of the different fluids present in the well according to the user data.

In the second tab of apparent T2, the software provide information of various fluid. The T1 value which is in microsecond in gas, oil, water and mud filtrate are 1450.65, 3377.24, 1.14(intrinsic) and 8266.35(bulk) respectively. The hydrogen index of the gas, oil and water are 0.12, 0.88 and 0.98 respectively. The diffusivity are in the form of 10e-5 cm2/s of gas, oil, water and mud filtrate are 302.58, 2.04, 5.87 and 5.51 respectively.

I can conclude with the information provided by the software of “Petrosite” that the volume of water, oil and gas are 8%, 7% and 5% respectively from the total porosity of twenty percent, as provided by the user. The polarized volume of water oil and gas is of 7.86, 6 and 0.61 respectively with the total polarised volume of 14.47. The hydrogen index total volume of water, oil and gas are 7.86, 6.18 and 0.61 respectively with the total of 14.65. The percentage of polarized hydrogen to the total HI is 98.78 percent in the given time of the polarization or Twait.

The polarization curve help to estimate the total percent or part that is polarised in the fixed wait time by the user. As it can be seen that while fixing the wait time of 12s, all water and gas is polarized and almost all water is too polarised in that time period. From this, the user confirm the time of stay that each depth the instrument must take for best result or total polarisation. Due to which the best result can be gathered as it polarised all the hydrogen present in the fluids.


Fluid Properties

	Water	Gas	Oil	Dead Oil	Mud Filtrate	Un
Temperature	71(160)	71(160)	71(160)	16(60)		C(
Pressure	1200(8)	1200(8)	1200(8)	15(0.101)		psi
Density	0.98	0.05	0.70	0.82		g/c
Viscosity	0.39		0.79	4.67		cp
Diffusivity	5.87	302.58	2.04	0.29	5.51	10
HI	0.98	0.12	0.88	1.00		
T1B	8808.00	1450.65	3377.24	591.30	8266.35	ms

Apparent T2

	T1 (ms)	HI	D (10e-5cm2/s)	A-group T2,LM (ms)	B-group T2,LM (ms)	C T
Gas	1450.65	0.12	302.58	33.94	2.94	3
Oil	3377.24	0.88	2.04	2039.75	386.31	2
Water	1.14(intri)	0.98	5.87	1.14	1.13	1.
Mud Filtrate	8266.35(bulk)		5.51			

Estimated Fluid Volumes

	Water	Oil	Gas	Total
Total Volume	8	7	5	20
Polarized Volume	7.86	6	0.61	14.47
HI Corrected Total Volume	7.86	6.18	0.61	14.65
				98.78%

Figure 14 Summary of the total data feed by the user.

CHAPTER 4. RESULT

MRIL pre job planning was used and performed in order to select an acquisition mode that help to meet the objectives of my work for logging the MRIL.

Based on the objectives, it has to be considered and the expectation that the reservoir fluid be oil. The type of activation which is selected for logging the MRIL in the given well is named as D9TE512. The reason behind the use of D9TE512 activation is its sensitivity to diffusion and uses the sequences with similar wait time but different echo spacing.

The MRIL acquisition parameters are listed in the given below table.

Group ID	Tw (ms)	Te (ms)	Ne	Repeats
A	12005	0.9	500	
B	12004	2.7	166	
C	20	0.6	10	24 PAPS
D	12006	3.6	125	
E	12007	4.5	100	

Table-3: Activation Parameters

Well Log Data

The wireline MRIL logging data were acquired by HLS Asia Limited. These MRIL data were also used to perform the 2DFC-T2D analysis, which is independent of the conventional logs. The MRIL data were acquired with the recommended activation, D9TE512 and at the logging speed of 0.7 m/min. The 2DFC-T2D interpretation was performed over the intervals as per required of the project as well as the client.

The conventional data of the well log is also acquired by HLS Asia Limited.

The well logs were in good condition overall through the main zones of interest. As it has been checked with the help of phase error (Mu) and phase noise (sigma) with respect to its depth and gamma ray log values. That help in minimizing the error which may came while processing the data under specific conditions.

The noise is proportional to the sum of all the signals from the different lines because each signal component see the same B_0. Note that the dominant part of the noise is phase shifted by 90^o compared to the signal. Therefore the real part of the signal determines the noise of the imaginary part and vice versa, which is characteristic for a phase error - if the cosine component of a signal is at its maximum, a small phase error ϴ changes its amplitude only proportional to ϴ square, while the corresponding complex component with a sine shape is at a zero-crossing and therefore changes linearly with ϴ.

The phase error should be in line close to zero which minimize the error in each depth value of processing data. The phase noise is due to the magnetic field instabilities which propagate into NMR data such as FID's and their Fourier transforms. This is of great importance for processes like the free precession of spin magnetization, where phase noise accumulates with time. Low-frequency noise has a much bigger influence on the affected process than high-frequency noise.

The phase noise line should be close to one. It is because while reducing the sigma value close to zero or nearly zero than data is extremely manipulated and difficulty came to derive the actual result or understand the real problem of the zone. If the sigma value is too high then there will distraction from the result.

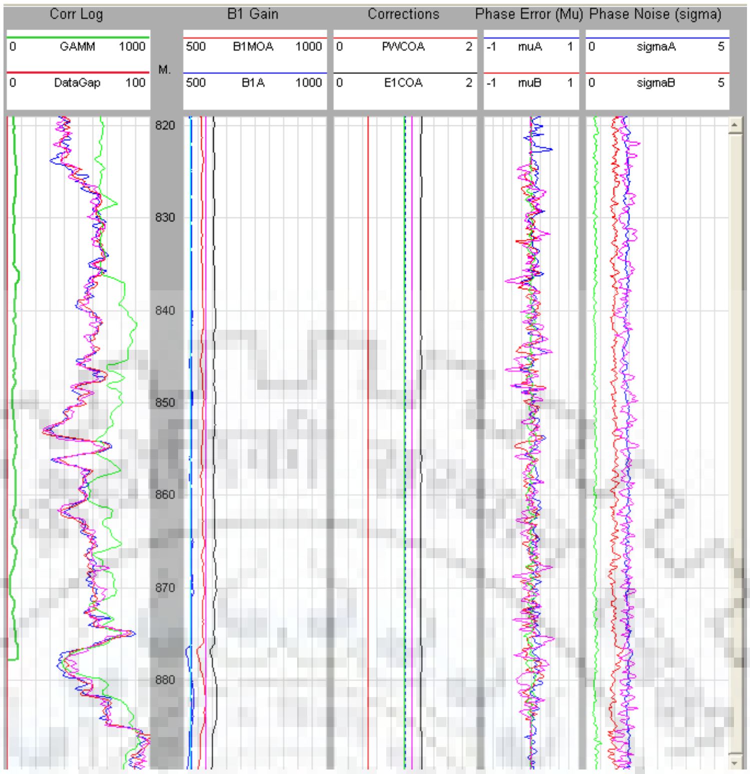


Figure.15– Estimation of Phase Error and Phase Noise

4.1. Result from the conventional logs

The provided well log data is a conventional log data of the field of my work. This thesis considered the depth interval of 800m to 900m. As it is proposed as effective productive depth of my field area. The well log data have the information of its depth, stratigraphy, gamma ray log, spontaneous potential log, caliper, bit size, resistivity logs of different depth of investigation, neutron log and bulk density log. The other tracks information are derived from the data of the earlier mentioned data whether it is effective porosity, effective saturation or volume of shale.

Discussing on gamma ray log, the most of region between 800 to 900 metres are non-shale area (sandstone). Almost a metre thick shale beds found in between the stratigraphy including Tarapur formation (shale) of four metres thickness. But when the track one for gamma ray log especially in Tarapur formation, very few trace of shale presence can be detected from the conventional log table. That's the start of our problem. It may be any of the reason for this problem.

Coming onto the resistivity logs data in the Track 2, all depth resistivity data whether it is deep laterolog (LLD) or shallow laterolog (LLs) or microspherically focused (MSFL) logs are developed for better understanding of the well. Due to that easy comparison between the different zones whether uninvaded or invaded or flushed zone is possible and reduces workload too. Most of the part of the data or stratigraphy have low resistivity zones with slight deviation in the output produced. More deviation can be seen in the depth of 840 metres to 845 metres compare to the previous deviations in the above data till 840 metres. A large deviation can be seen in the zones of 867-871 metres and 880-885 metres and else zone remain low resistivity profile zone with slight deviation. In the zone of 880-885 meters, the resistivity is comparably high from the surrounding zone with better gamma ray log data. In the above mention zone there may be the presence of high resistive fluid whether it can be the oil or gas or freshwater. But in the above mention zones also, the differences in the different type of resistivity logs having different depth of investigation can't be seen in the output result. Whether the shallow focussed log or LLs or LLD all have the same resistivity throughout the zone which means the resistivity is same at all depth of investigation which create doubt about present fluid and its flow in different direction. That is the reason which increase the doubt percentage in the problem.

After seeing the result from gamma ray log and resistivity logs, moving on to the porosity logs such as neutron and density logs. It is know that the cross-plot of neutron and bulk density log tells about the presence of gas concentration in that specific zone and both logs closeness convey about the presence of water and oil with respect to the resistivity and gamma logs. In the starting of the zone of 800 metres to 900 metres, the value of neutron porosity log is very high and bulk density is in between 2.1 to 2.4 gram per centimetre cube. In between 840 to 850 metre depth, the neutron and bulk density log data come close to each other. Again gap between the two logs can be seen after 850 metres. Closeness between the logs starting from the depth of 865 metres to 874 metres can be seen. One more point can be noticed that in both the zones, the resistivity is higher as compare to the other respective zones. Noticing the zone of 880-885 meters where the resistivity is high but the neutron log and bulk density log have large gap and both the log data are too high. The resistivity of the resistivity logs are all same with different depth. Which seems unusual for the presence of any type of hydrocarbon whether is in oil or in gaseous form.

On the fourth track of the log, the effective porosity of the log for the respective depth. This track is develop with the help of neutron and bulk density log. In the quantity tab of TechLog software, the effective porosity is calculated using the neutron log and bulk density log for different depths. The effective porosity varies with different stratigraphy as it can see that the effective porosity of Kand formation is about fifteen percent with slight variation. Now moving down from the Kand formation to Babaguru formation, the porosity drop can be seen at the depth of 805 meters. In the Babaguru formation porosity varies almost zero to even forty percent. In the Tarapur formation, porosity dips to around ten percent. In the Kalol formation the maximum formation effective porosity is about twenty five percent and minimum of around zero. Considering the zone which appears to be productive, it can be concluded that at the depth range of 840 meters to 850 meters, it has the porosity of about fifteen percent. At another depth range from 866 meters to 874 meters, the effective porosity varies from forty percent to twenty percent. One higher resistivity zone of 880-885 meters is having very low effective porosity nearly to ten percent. In the rest of the places, the porosity is around ten to twenty percent except the Tarapur shale.

Moving onto the fifth track of Indonesia saturation, the saturation calculation is present in the quantity tab of Techlog in the subpart of porosity and saturation. The data required for calculation of saturation is deep resistivity, effective porosity and shale volume. The formula was empirically modelled with field data in water-bearing shaly sands, but the detailed functionality for hydrocarbon-bearing sands is unsupported, except by common sense and long-standing use. *Sw* results from the formula are comparatively easy to calculate and, because it is not a quadratic equation, it gives results that are always greater than zero. The *Sw* output is usually taken to be the water saturation of the effective porosity, but it has been recently suggested that the output is likely to estimate *Swt*. The saturation of Kand formation is almost equal to one. Discussing on the Babaguru formation, the saturation is almost eighty percent in the zone of 806 to 826 meters. In the one of the considered productive zone of 840 to 843 meters, the value of saturation is around sixty percent. In another zone having depth of 867-871 meters, the saturation is too low of about thirty to twenty percent as an average. In the Tarapur shale the saturation is hundred percent. In the Kalol formation, the saturation is hundred percent except the depth from 878 to 884 meters where the value is about sixty percent.

In the last track that is sixth track, which is the combination of shale volume and effective porosity. The combination of above mention two are present in the summaries tab of quantity tab. It require input data of shale volume and effective porosity, which help to generate the result in the sixth track of the log. This track tells about the percentage of shale present at different depth with the effective porosity left in the given depth. Firstly considering the Kand formation, about fifteen to twenty percent of shale volume and the yellow part shows the effective porosity present with bound with the left uncoloured part of the track. It seems that Kand formation has good effective porosity with increasing shale volume with the depth in the formation. Moving onto the Babaguru formation, the average shale volume is about twenty five percent and high effective porosity in large part of the zone. Considering the depth from 840 meters to 850 meters, the concentration of shale volume is low with very high effective porosity. Another zone from 867 meters to 871 meters having shale volume equal to almost zero and effective porosity of about forty percent giving a very clean sand zone. Whereas in the Tarapur formation, the presence of shale volume is high with least effective porosity. At last, the Kalol formation, have high shale volume concentration in the starting of the stratigraphy and decrease in shale volume with the depth. The effective porosity is high in the Kalol formation.

In last the conclusion can be drawn from the conventional log data that there are few zone at depth of 840 to 850 meters and 867-871 meters which can be productive but there is a conviction about the mention zones and other unmentioned zone is really profitable. The reason behind this is the log data and the result obtain from the given data. The result which came is not that much trustworthy as it is not clear at any of the depth. It can be seen that if the gamma ray log value is good then other values of resistivity log or porosity log is not appreciate it. The resistivity logs are all overlapping each other even the microsphercially focussed log and deep laterolog, in the above mention zones also. The porosity logs like bulk density and neutron log are showing large difference in the value of porosity even in the so called productive zones. The effective porosity is also showing random result which is almost next to impossible.
These all can be derived from the above 100 meters of well log data.

It is difficult to derive any appropriate result from the conventional logging data. None of the track shows a better result which may helpful in driving any conclusion. The error in the conclusion of the result is can be too high as output of logging data is almost showing totally different result from the theories on the Mehsana oil field. The cognition is the presence of silt, clay particles with the ferrous carbonate. The integrated study reveals that the Cambay shale reservoir possesses thinly laminated silt. The laminations are sometime replaced by siderite due to prevalence of digenetic influence resulting to non-reservoir at places. These are well identified by imagery data. The silt laminations are continuous, and sometimes discontinuous. The host of the silt laminations is clayey in composition, with disseminated discrete organic particles (Ajay Kumar et. al). Due to the above mentioned reasons, the accurate value of properties of rocks (formation) can't be retrieved using conventional logging technique as it is affected by the presence of impurities in the formations. These impurities can be of any type due to the presence of very small size grains, ore minerals, inorganic gas concentration and many other too. Therefore, I have to move to non-conventional method of logging and one of the prime example of non-conventional logging technique is neutron magnetic resonance logging. The major reason for choosing NMR is its properties as it is not affected by the impurities present in the formation. NMR logging, measures the induced magnetic moment of hydrogen nuclei (protons) contained within the fluid-filled pore space of porous media (reservoir rocks). Unlike conventional logging measurements (e.g., acoustic, density, neutron, and resistivity), which respond to both the rock matrix and fluid properties and are strongly dependent on mineralogy, NMR-logging measurements respond to the presence of hydrogen protons. Because these protons primarily occur in pore fluids, NMR effectively responds to the volume, composition, viscosity, and distribution of these fluids like gas, oil and water. NMR help in getting the better result as compare to the conventional logging data and also help in identifying the productive and non-productive zones with more accurate and more precise values. Because of its simulation in the presence of hydrocarbon and water (proton) only not by any clay particle or ore mineral succour in gaining finer outcome. The next logging data, I am going to present is of NMR data.

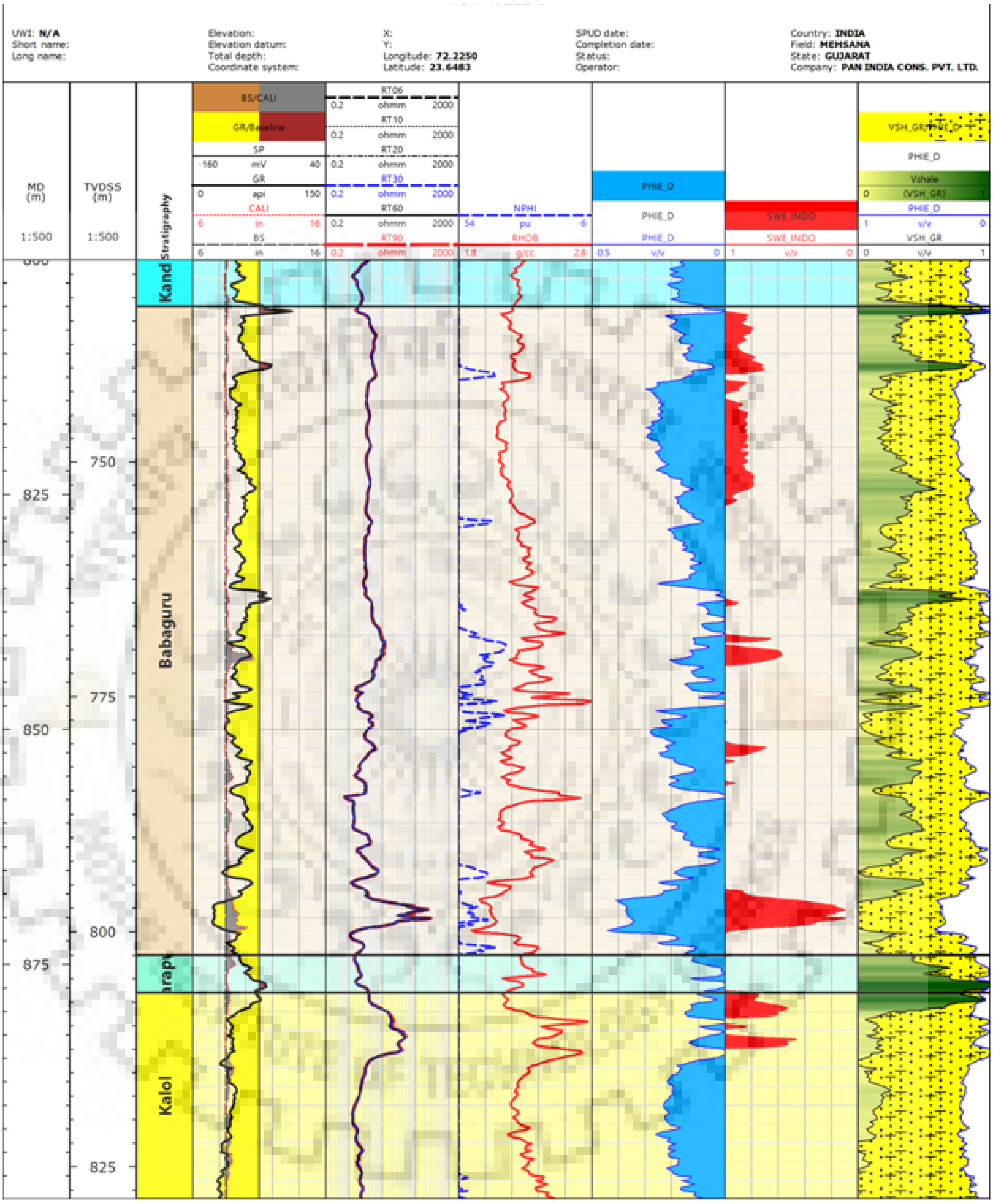


Figure 16 Conventional log data of depth between 800m to 900m.

4.2. Result from NMR log

In the NMR log data, two extra track is present with the other conventional log. These two tracks are of T2 porosity with type of pores and the T2 log mean. The fluid component is subdivided into bound and free subcomponents. The hydrogen nuclei of clay-bound water are adsorbed on the surfaces of clay grains. These hydrogen protons can be polarized by NMR-logging tools and recorded when a sufficiently short *TE* is used. Similarly, hydrogen protons in capillary-bound water and movable fluids (e.g., free water, mud filtrates, oil, and gas), are polarized and recorded by NMR-logging tools with appropriate values for *TE* and *TW*. In the former track, the plain green colour part is of free fluid, black dots are for bound water and green-white check is of micropore. The cumulative of all three form the total porosity. T2 relaxation occurs when the precessing proton system transfers energy to its surroundings transfer in energy and also through dephasing. The T2 decay associated with a single pore size in water-saturated rocks is proportional to the pore size. In fact, because reservoir rocks typically comprise a distribution of pore sizes and frequently contain more than one fluid type, a CMPG T2 spin-echo train actually consists of a distribution of T2 decays, rather than a single T2 decay.

Starting with the Kand formation, almost all porosity is in the form of micro porosity and some free fluid, after the depth of 800 meters to 805 meters at can also be seen in the T2 distribution. Considering the T2 log distribution, most of the part or the largest hump can be seen in the micro bound water part and a few small bumps can be seen at few distance from the larger humps. The small bumps at that distance show the free fluid part of the porosity. The bound pore is almost missing in Kand formation at depth of 800 meters to 805 meters. The mean T2 log is in the micro pore bound zone of NMR log.

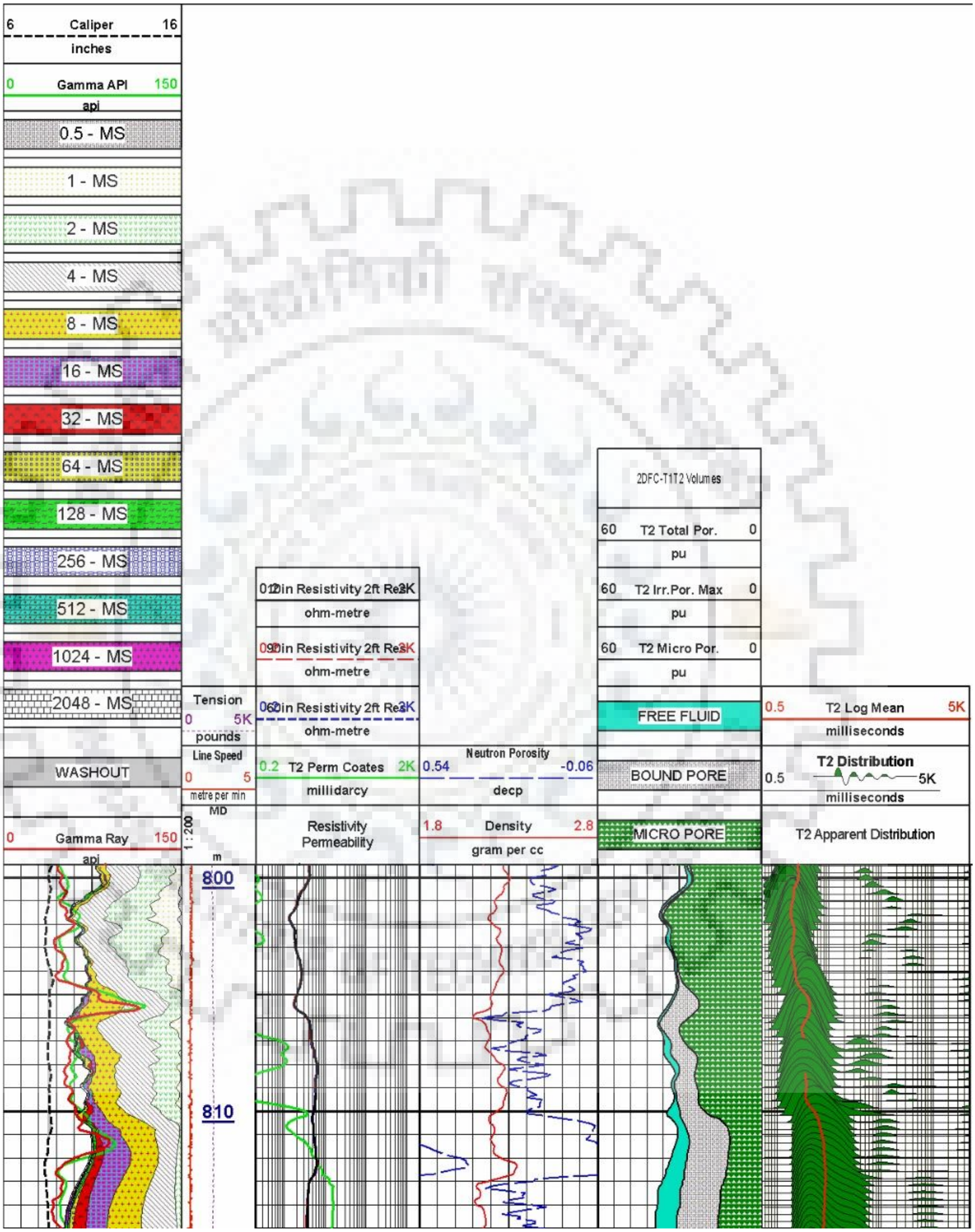
Moving on to the Babaguru formation, starting from 805 meters to 874 meters. From the starting of Babaguru formation, the bound pore percentage increases with decrease in micro pore. The hump of the T2 distribution shifted to slightly to left and very minute free fluid can be seen to the depth of 807 meters. At that depth zone from 805 meters to 807 meters the mean T2 log is moved too to left. From the depth of 807 meters to 810 meters, there is an increase in free fluid pores and small humps in two parts that can be justified as bound pore humps and free fluid humps. From the depth of 810 meters to 825 meters, all type of pores are present in good percentage comparing the previous lithologies. That can also be seen in the stretch diagram of T2 distribution where micro pore and bound pore almost coincide and form stretch hump.

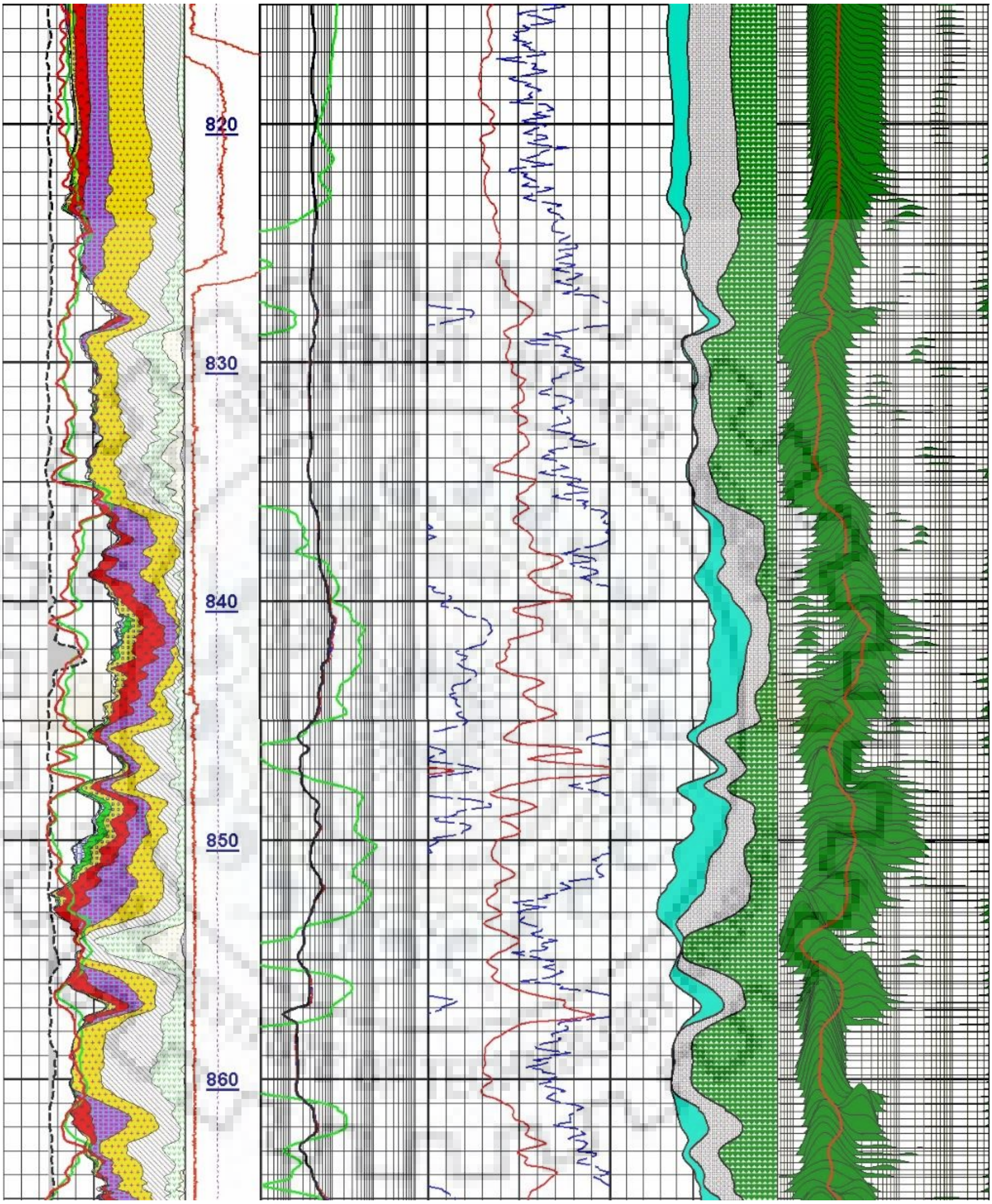
At the time gap, the free fluid bumps can also be noticed, but the problem is the resistivity which is low at the above mention depth. Going from the depth of 825 meters to 836 meters, the pore of free fluid is absent and bound pore and micro pore sum up the total porosity. The depth from 837 meters to 846 meters, shows increase in free fluid porosity, with constant bound porosity and very low micropore percentage. The NMR graph is also shifted towards right side with humps in the oil zones too. This shift is justified by the resistivity logs also, in which increase in resistivity can be seen. It may considered as hydrocarbon zone. In the depth of 848 meters to 854 meters, a prove division of porosity whether it is free fluid or bound or micro pore can be seen the graph. A better NMR result can be seen in this depth with two or three humps too in the NMR log. A better result justification for the presence of all three type of pores can be seen in this part of the log table, through NMR log. The humps are shifted to three to four hundred microseconds, showing closeness to the presence of hydrocarbon. At this depth, the resistivity data is not well developed in this zone but with the help of NMR data, it can be well explained. The presence of pores as well as content in that pores can be better understand by the NMR log in this zone of depth. Increase in micro porosity in depth of 854 meters to 855 meters and shift of mean T2 distribution more towards the left. Moving to the depth from 856 meters to 858 meters and from 861 meters to 865 meters. The type of porosity is almost well distributed, in the above mention zones. In this zone, the micropore concentration is high as well the bound pore and free fluid. The two humps can be easily seen in the T2 distribution log data which clarify the micropore and bound pore. The one of the most important zone from the 868 meters to 871 meters, where the resistivity is too high and now seeing the T2 time porosity, it is well distributed in all three form of porosity whether free fluid, bound pore and micro pore. Considering the free fluid pores, the percentage present is in considerable amount for a better reservoir. The T2 distribution log is having two humps in the form of micro and bound form of fluid. Few more humps can be seen in the distribution curve at around thousand microseconds. Which is almost equal to the T2 value of oil which is gathered from different studies. Confirming the presence of hydrocarbon in the given zone more accurately.

After the Babaguru formation, the next formation is the Tarapur shale (or formation) which shows high gamma and low resistivity zone from the depth of 874 meters to 879 meters. Showing most of the porosity as micro pore porosity and rest as bound pore form. This can easily be seen in the T2 distribution log and the mean T2 curve both remain in the low T2 time value.

In last, Kalol formation which is form basically through regression. From the depth of 879 meters to 885 meters, it shows the porosity having good percentage of free fluid part and decrease in bound pore and micro pore. Due to the more concentration of micro pore and free fluid comparing with least of bound pore to certain depth. There are presence of two separate humps in the T2 distribution log, which confirm the two types of pore present but the value of free fluid hump is close to forty to sixty microseconds and small bumps near to the hundred to thousand microseconds. This clarify more the presence of hydrocarbon in the above mention zones. From the depth of 886 meters to rest of the depth of 900 meters of this formation is having porosity in the micropore form with least value of T2 time. In this zone of 886 meters to 900 meters, the resistivity is low, clarifying the result that is produce from the NMR logging.

With the help of NMR logging, it become easily to find the presence of type of porosity in different depth of the well data. The conclusion which can be gathered from the conventional logging tools is better rectified and ameliorated with the help of unconventional method of NMR logging. Due to the presence of impurities in the Mashana area of Cambay basin, the conventional method of logging is not giving the better result as it is affected by the impurities. The unconventional method of NMR log is affected by the proton concentration and help to generate the result like type of porosity whether it is micropore or bound pore or free fluid, which give better result from the conventional method. From the NMR T2 distribution logs, the type of fluid can also be identified based on values of T2, as mentioned in the table 1. Where T2 value of oil is around of hundreds microseconds, gas around thirty to sixty microseconds and brine value varies from ones to hundreds. Through these results, the fluid is almost can be identified and can be better understand from the upcoming data and logs. The next NMR log include the permeability and cut-off of micro, bound and free fluid.

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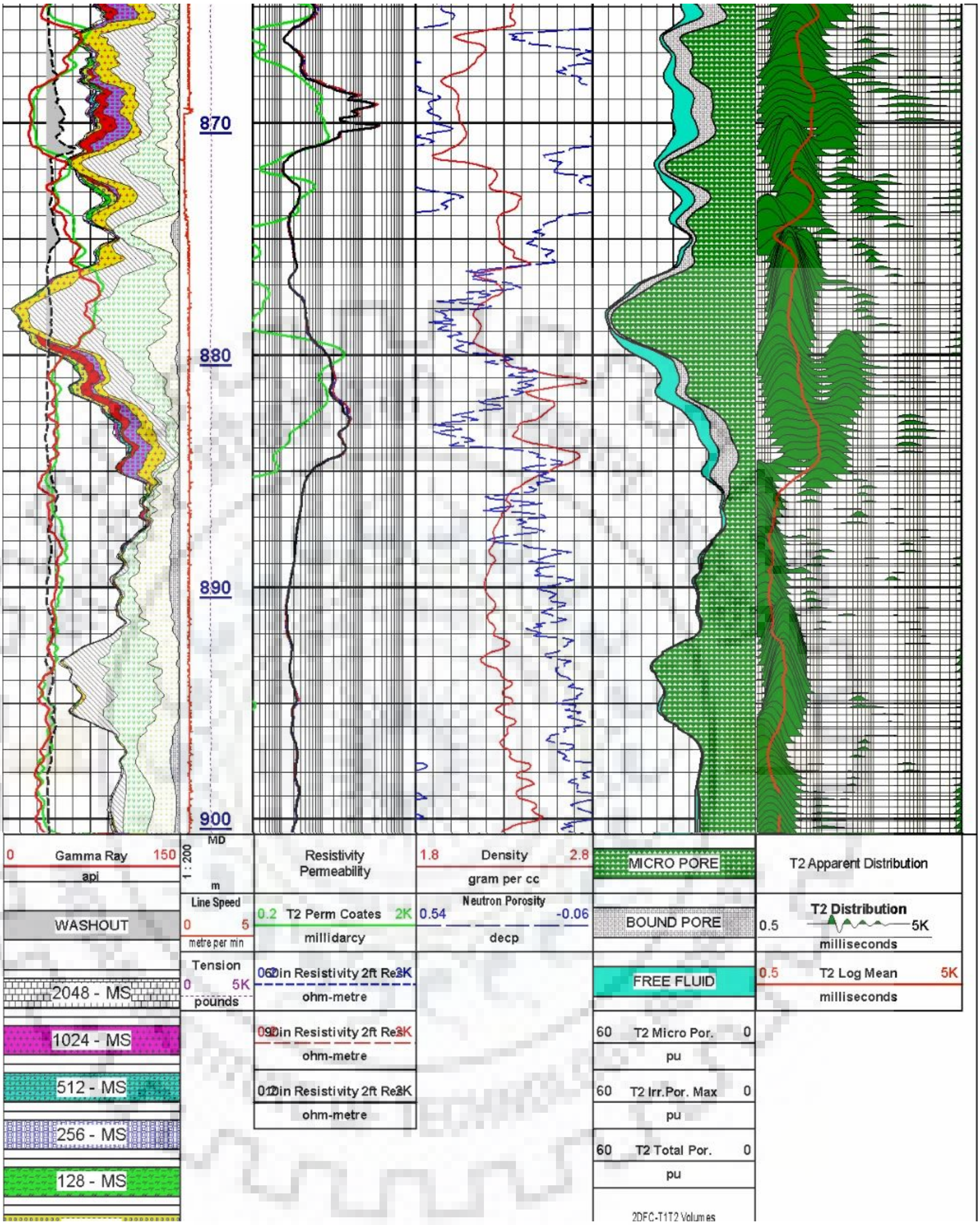

Figure.17 – NMR log result showing mean T2 distribution and type of pores

4.3. NMR log with permeability and Cut-off of fluid

In this log data, the cut-off of 7 microseconds and 33 microseconds. The clay bound irreducible water and capillary bound irreducible water is separate at the cut-off of 7 microseconds and at 33 microseconds the bound irreducible water and producible fluids can be distinguished or divided. This log data also have the value of permeability of the formation with its respective depths. The method which is used for deriving the values of permeability in Petrosite of Halliburton logging services is known as T2KCOAT.

Talking about the permeability of the well from the depth of 800 meters to 900 meters is around twenty to hundred millidarcy. The highest porosity is three to four hundred millidarcy and least around 0.1 millidarcy. As you can see the permeability data in the above log is from 820 meters to 890 meters which include the Babaguru formation, Tarapur formation and some parts of Kalol formation. The rise in permeability starts from 840 meters to 845 meters with average value of ten millidarcy. Close to this depth from 846 to 855 meters which is also a part of Babaguru formation, shows highest permeability of sixty millidarcy with the average value of twenty millidarcy. In the further depth from 861 meters to 866 meters, from 868 meters to 871 meters and from 879 meters to 885 meters, the increase of permeability can be seen with an average value of three to four millidarcy. Considering the formation of Tarapur which is from 874 meters to 880 meters shows a discontinued permeability. The Kalol formation which starts after the depth of 880 meters shows a little zone of permeability at the starting of the formation with an average value of three to four millidarcy and no permeable zone in the further depth of formation till 900 meters.

Moving on to the T2 distribution data of the NMR logo. It has two straight cut-off lines, one is green in colour which differentiate the clay bound irreducible fluid from capillary bound irreducible fluid and the other red line is for differentiating the bound irreducible fluid to producible fluid. While considering the depth from 820 meters to 825 meters, the fluid is better divided in clay bound and capillary bound. Few patches of humps can be seen after the cut-off of 33 microseconds which is considered as producible fluid or free fluid. From 825 meters to 835 meters, the fluid is bounded majorly in clay bound pores, as it can be easily visible from the NMR log that all the humps in the described zone is before the cut-off of clay bound and capillary bound fluid. It clarify that this zone have very intact type of fluid. Moving from 835 meters to 840 meters, all the fluid is bounded in the capillary bound pores and none of the fluid can be seen or found in the clay bound or as producible fluid. Now from the depth of 840 meters to 855 meters, the permeability of this zone is high and the T2 distribution is equally distributed in this zone, much of the humps can be seen in the producible fluid zones and porosity of clay bound and capillary bound can also be seen in the given zone of depth. The humps of the producible pores are spread to the T2 time of hundreds of milliseconds which reflects the presence of hydrocarbon in the respective zone. While looking in the log data from 855 meters to 865 meters, almost all the part of the log is found in the cut-off of 33 microseconds that is the cut-off of reducible and irreducible pores. Justifying the non-producible zone of the well in the Babaguru formation. From the 865 meters to 875 meters, in this zone of the well most of the humps can be seen in the 7 microseconds cut-off that means it is clay bounded pores and rest of the bumps can be seen after the cut-off of 33 microseconds and bumps comes up to the thousand microseconds T2 value, justifying the most productive zone of the depths in which I am working. Again from the depth of 875 meters to 879 meters is a zone of irreducible fluid and pores, found majorly in the clay bounded pore. Noticing the depth range of 879 meters to 885 meters, which is having a better permeability zone. It has most of its part as irreducible pores in the form of clay and capillary bounded. Some of its part can be seen after the cut-off of producible fluids and humps comes up to few hundred microseconds, justifying presence of hydrocarbon in the form of oil. After that depth of 885 meters up to the depth of 900 meters, the fluid is intact in the pore of clay bound pores.

From this log of NMR, one thing can be confirmed that it has some of the area or zone which is proved to be productive with the help of both conventional as well as non-conventional log (that is NMR). The NMR log data prove to be more effective in estimating the type of pores and also in fluid typing which can be seen in the further results that is gathered using or plotting 2DFC-T2D map.

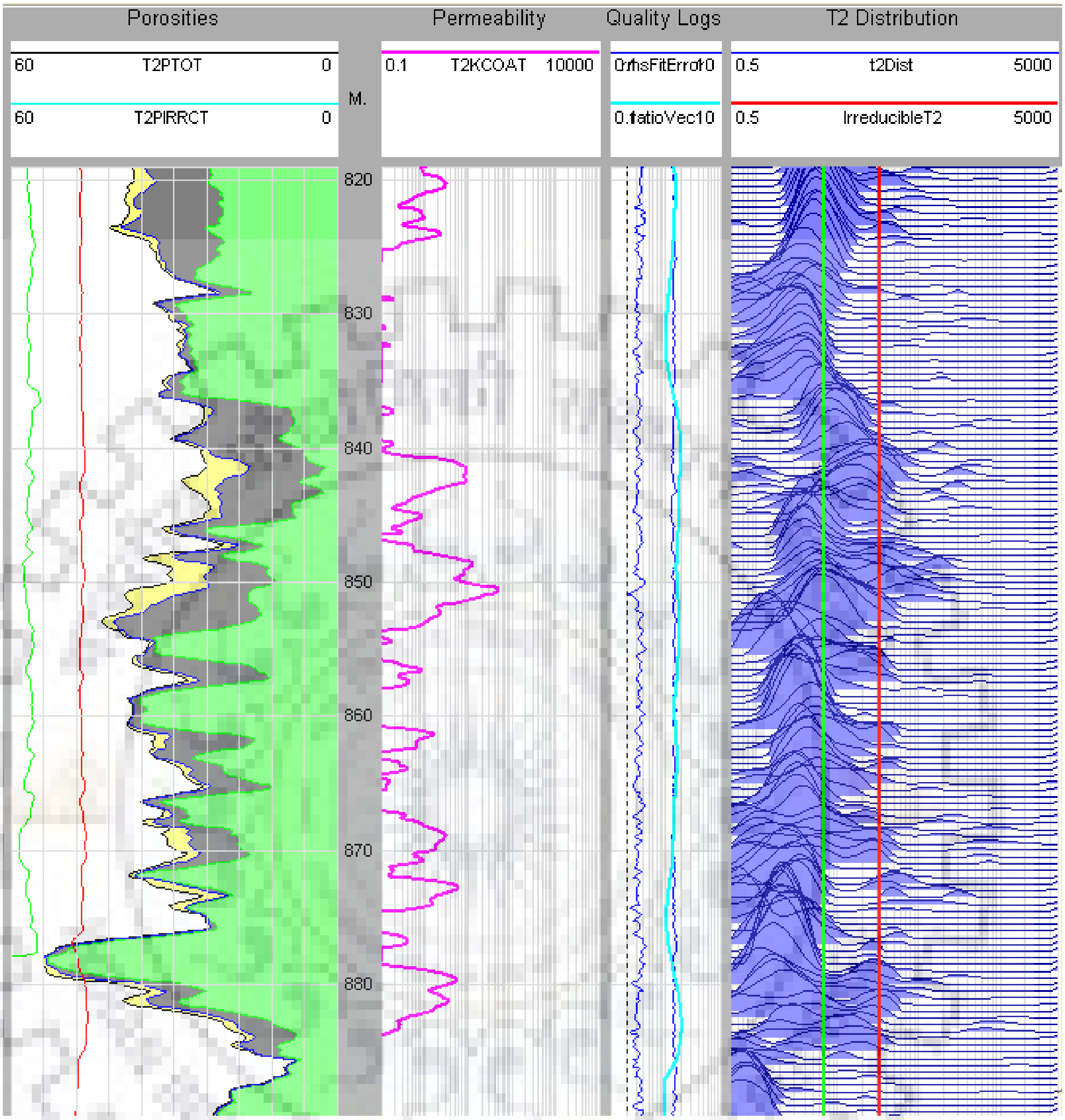

Figure 18 – NMR log data developed from the NMR studio of Petrosite software

2-Dimensional Fluid Characterization Interpretation Method

This method of 2DFC-T2D (Two Dimensional Fluid Characterization T2D) is a self-contained NMR processing model which is developed to help in evaluating NMR well data with 2 dimensional (2D) inversions of simultaneous multi-echo spacing T2 data. The most common or the primary application of 2DFC-T2D is for oil identification and quantification in either water-based or oil-based mud systems. The outputs that are generated through it, can be used with conventional logs to enhance and improve the log interpretation of oil and gas (methane) bearing reservoirs.

The 2DFC-T2D model neither assumes, nor relies on knowing, the nature of hydrocarbons present in the formation in most instances. However, the interpretation results which are derived is totally based on options available for selecting the drilling mud system for the well to be analysed. Selection of oil-based mud (OBM) or water-based mud (WBM) will determine how the 2D map partitions are initialized to distinguish individual fluid types.

Some specific activation sets are recommended to acquire the appropriate NMR datasets for applying 2DFC-T2D processing. These activation sets are identified within MRIL Prime and MTE (Multiple Te). These activation sets provide for a long wait time to achieve full polarization of all echo spacing and use a minimum of four different echo spacing with partial recovery activation.

The primary output from 2DFC-T2D is a 2D map of T2Intrinsic and Diffusion distributions; petrophysical quantities are extracted from these distributions. These quantities include gas, oil, heavy oil, moveable water, and bound fluid volumes for WBM environments, and OBM filtrate volume for OBM environments.

T2Intrinsic and Diffusion are simultaneously computed during processing. T2Intrinsic has no diffusion component and is similar to T1. In this report, “T2” is used to refer to “T2Intrinsic”. Individual T2 and Diffusion distributions for each fluid type are also computed from the 2D map and displayed as outputs.

2DFC-T2D is an analysis technique that only uses the MRIL data. The technique is optimized to identify methane gas and differentiate gas from liquids (either oil or water). Because this technique only uses MRIL data and the MRIL is a relatively shallow depth of investigation measurement, the fluid volumes and saturations determined are representative of the flushed zone. If there is mud filtrate invasion, this will affect the fluid volumes determined from this technique.

Processing appropriate activation sets for 2D NMR produces a 2D map that represents the simultaneous inversion of multiple echo train acquisition with respect to two NMR parameters, normally T2 or T1, and Diffusion.

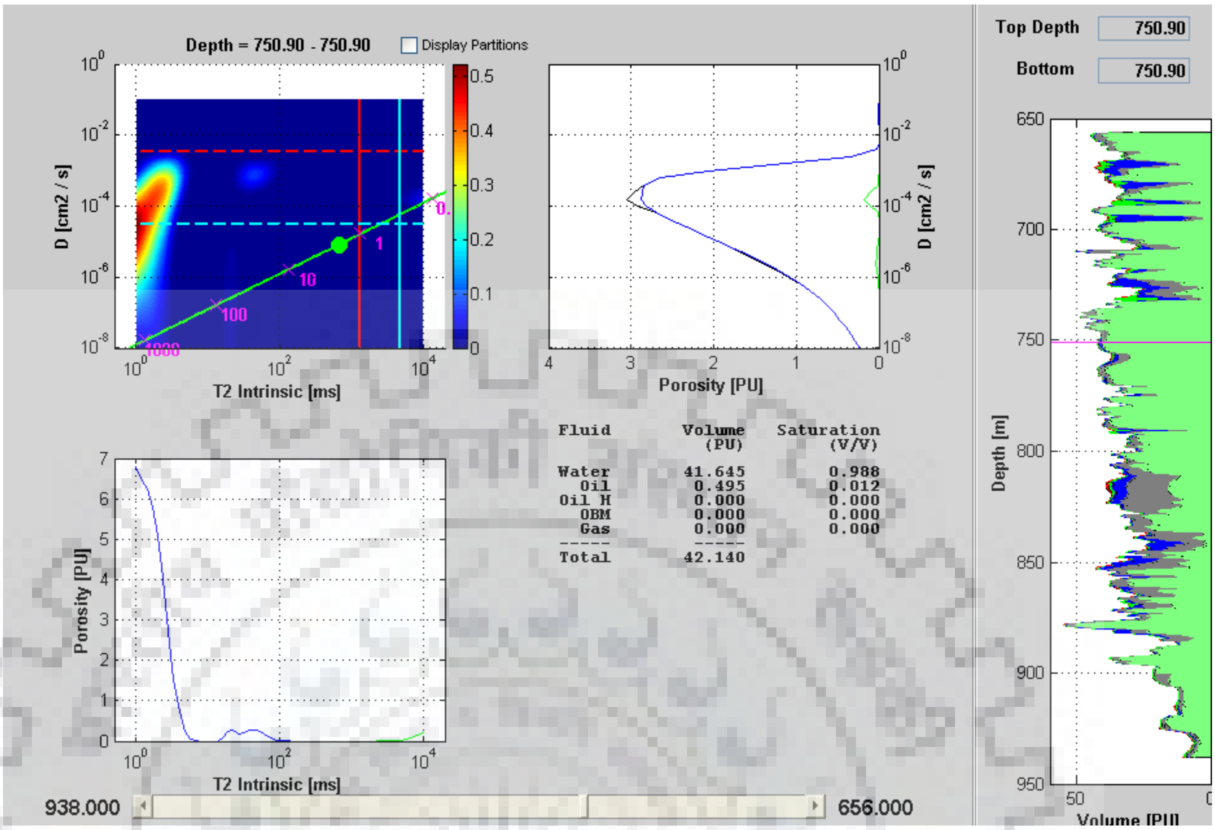

Figure 19: Workstation of 2DFC-T2D map in the Petrosite software of Halliburton

4.4. 2DFC-T2D Analysis and Interpretation Results

While doing the 2DFC-T2D analysis completed in the given well in the respective depth, the 2DFC-T2D maps were partitioned to solve for oil and water volumes. One special thing is that the 2DFC-T2D interpretation only uses MRIL data and does not require any inputs for lithology, matrix density or Rw. The MRIL reads approximately 2.5 – 3.5 inches deep into the formation so is affected by invasion and the MRIL fluid volumes represent invaded-zone fluids. The T2D interpretation worked pretty well for the given depth of the respective well and there is WBM filtrate invasion at few places. The description and interpretation of 2DFC-T2D product is shown in the given below figures and analysis is as follows:

In the interval of 840.7-840.7m in Figure 20, the 2DFC-T2D Map analysis shows bound water with feeble signature of oil. The side bar near the 2DFC-T2D map tell about the intensity of the fluid present and its presence in the specific area in the map reflects the type of fluid present in the respective depth. In the 2DFC-T2D map, the concentration of fluid is on the blue line of water and also with great intensity. As it can be easily seen that T2 intrinsic time value in almost normal which refers that most of the fluid is in the form of water are generally in capillary bound water. Some amount of fluid is bounded in shale or clayey particle, in its micro pores. Small amount of oil traces can also be seen in this depth, which is in the low diffusivity value referring lesser gas content in the oil. The concentration of oil is almost frail in this depth. Major part of the fluid are in bound form and also the type of fluid which is in larger content in the brine or water not the oil or gas. No intensity spot can be seen above the red line of gas that present at high diffusivity value. Confirms the lack of presence of gas there. The green line of oil have very vague intensity of concentration that reflects at this depth production is not profitable but presence of oil there. The presence is very small but it is there.

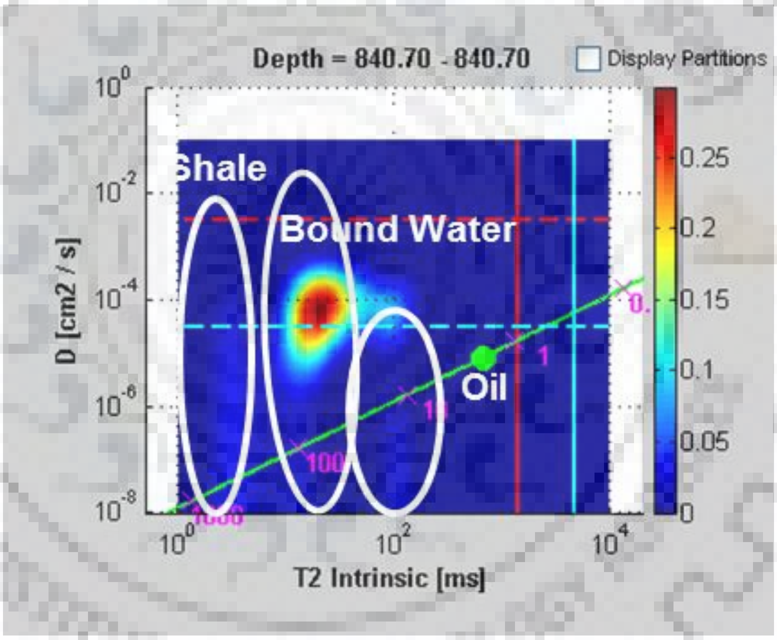

Figure 20- The plot of 2DFC-T2D map at depth 840.7m depicting presence of bound fluid and feeble signal of oil.

In the interval of 844.4-844.4m in Figure 21, the 2DFC-T2D Map analysis shows that there is signature of bound water and oil. The 2DFC-T2D map is somewhat similar to the 2DFC-T2D map of depth 840.7 meters but with some difference. The intensity of bound fluid at low value of T2 time which majorly refers as clay bound fluids, bounded in the clayey particles of formation. The trapped fluids in the micro pores are also have the property of high diffusivity which refers as trapped gas in the micro pores with brine or water with low diffusivity value. The larger concentration of bound fluid can be seen in the capillary bound pores with diffusivity value greater than blue line of water but less than the red line of gas. The bounded fluids in the capillary bounded pores includes water with may be gas traces too. Again in this depth, the presence of oil is frail this can be easily visible in the signal of oil along the line of oil. Very dim signal of oil reflects not a productive depth but presence of oil either in the trace amount is there in the depth of 844.10 meters.

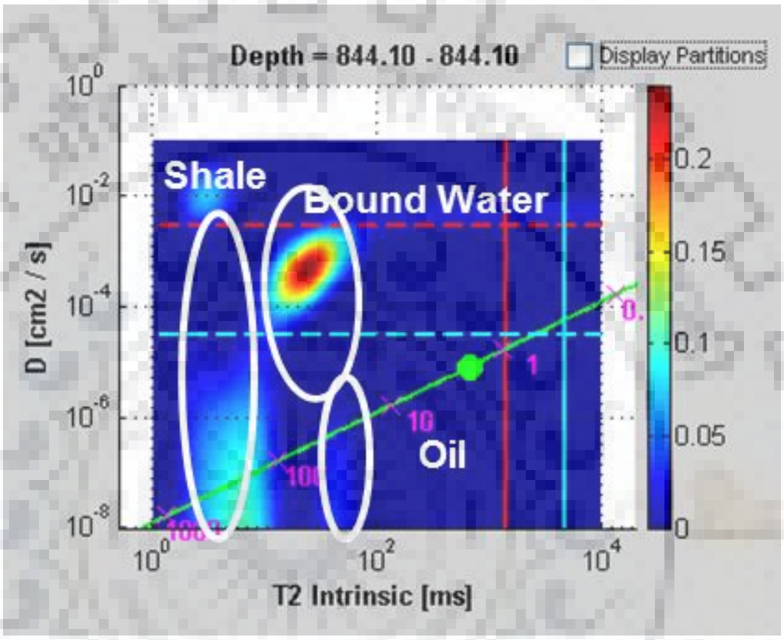

Figure 21 - The plot of 2DFC-T2D map at depth 844.1m 7m depicting presence of bound fluid and feeble signal of oil.

In the interval of 851.0-851.0m in Figure 22, the 2DFC-T2D Map analysis shows that there is indication of oil and bound water. Water signal is also noticed in 2D map. This water signal appears to be mud filtrate. The signals of either clay bounded or capillary bound fluid is of almost same intensity. High signals of shale water or clay bound fluid which reflects high concentration of fluids are trapped in the micropores, it may contain trapped gas too. The second peak which appears to be of bound water as its T2 intrinsic value is low, around hundred microseconds but it also touches the green colour oil line. A signal on the line of water can be seen in the 2DFC-T2D map. It is not showing any signal regarding the gas content in formation which can be seen above the red colour gas line. It may happen that it is trapped in the clay bound pores as the shale trapped fluid signals are also present between the water and gas line. It show some inaccurate indication of presence of oil in the 2DFC-T2D map but it is hardly visible in the NMR T2 distribution log means no big humps after the cut-off of reducible and irreducible fluid that is at 33 microseconds.

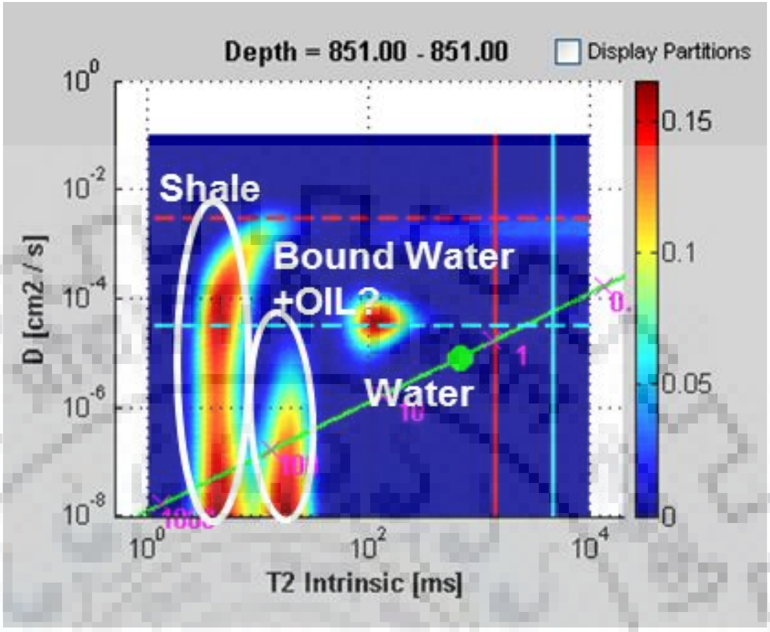

Figure 22 - The plot of 2DFC-T2D map at depth 851.0 m.

In the interval of 865.5-865.5m in Figure 23, the 2DFC-T2D Map analysis shows that there is feeble signal of oil with bound water. This 2DFC-T2D map has moderate signal of shale or clay bound fluid at low T2 intrinsic time value with large range of diffusivity value. The type of fluids that can be trapped in the shale or clayey content of rock formation are may be water and gas as the signal goes greater than red line of gas. The capillary bound fluid signals can be seen in the 2DFC-T2D map at low T2 intrinsic value which is greater than clayey bound fluid. A strong signal can be seen in the bound fluid zone just between the red line of gas nad blue line of water. The signal of oil can be seen which is very little but confirms the presence of oil in the zone. The concentration of oil is very low which can be deduced from the 2DFC-T2D map and also the type of oil is also heavy as the signals are at lower T2 intrinsic time value. A error can also be seen in the 2DFC-T2D map at very high T2 intrinsic value near the cross line of water and oil. From this map, it can be concluded that very little trace of oil can be seen in the given depth and the bound water content is high in the depth of 865.50 meters.

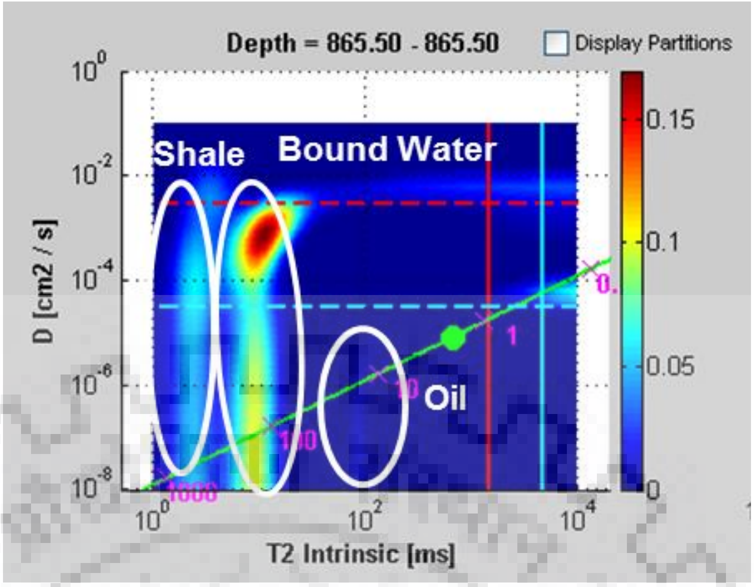

Figure 23 - The plot of 2DFC-T2D map at depth 865.50 m.

In the interval of 867.0-871.0 m in Figure 24, the 2DFC-T2D Map analysis shows that this interval is oil bearing. In the interval of 867-871 meters, the oil signals are high and new other information can also is generated through this 2DFC-T2D map. The clay bound fluids are water and gas, the signal of water can be seen in the lower diffusivity and T2 intrinsic value and the strong signal of gas can be seen above the gas line at high diffusivity and low T2 intrinsic value. The bound water signals are too very strong on the line of water. The two signal of oil can be seen in the above mention intervals. One of the oil signal is present at moderate T2 intrinsic value, this signal is slightly weak and the other signal is at high T2 intrinsic value on the green line of oil. This zone has the oil content that can be producible and it can be an oil bearing interval, it is due to the moderate signal of oil at high T2 intrinsic time value which reflect high gas to oil ratio.

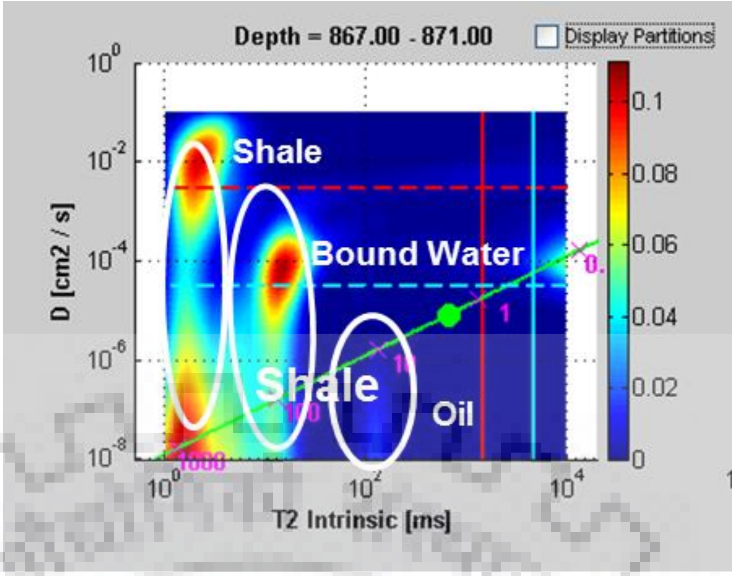

Figure 24- The plot of 2DFC-T2D map in the interval 867.0-871.0 m.

In the interval of 879.70-882.70m in Figure 25, the 2DFC-T2D Map analysis shows the presence of bound water and feeble signal of oil. In this interval of depth, there is strong signal of clay bound fluid can be seen, that signal is on the red line of gas confirms the presence of trapped gas in the respective 2DFC-T2D map. The capillary bound fluids also have good signals between blue and red line of water and gas respectively. The thing that can be concluded in this 2DFC-T2D map is that only bound fluid signals are very high but the oil presence is very low as can be seen through the signals.

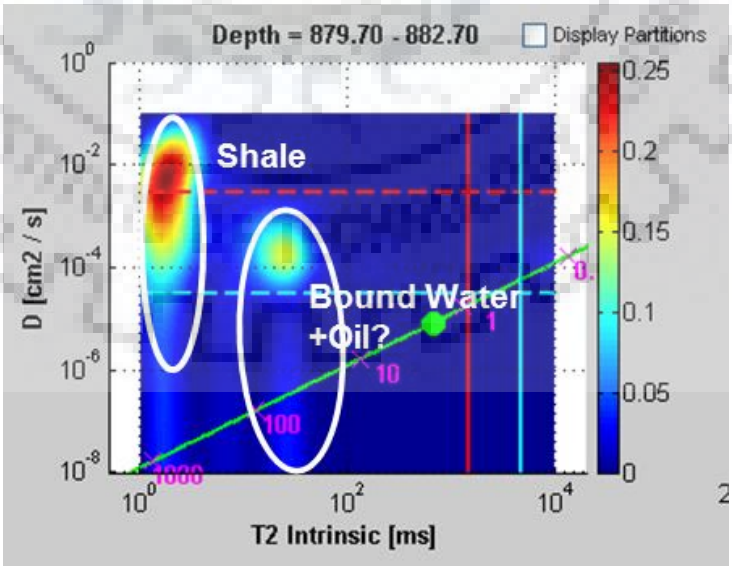

Figure 25- The plot of 2DFC-T2D map in the interval 879.7-882.7m.

CHAPTER 5. CONCLUSION

Integrating the conventional and advance technology logging tool for complex reservoir characterization, the following conclusions can be drawn:

- Most of the regions have irreducible water and they are trapped in the micro-pores and bound-pores.

- Due to the large concentration of bounded fluid, very few region have free fluid in the interval depth of 839-845m, 846-853m, 867-871m and 880-882m. In these intervals movement of fluid can be seen.

- Large percentage of micropores are present in respect to the reducible pores.

From the 2DFC-T2D Map, these conclusion can be made:

- The MRIL data show presence of oil within the intervals 839.0-846.0m, 847.5-853.5m, 861.0-866.0m, 868.0-871.5, and 879.0-885.5m.

- Hydrocarbon shows are seen in side wall core cut at depths 841.0m, 865.0m, 869.0m, 870.0m, 871.0m, 882.0m, 883.0m, and 884.0m corroborating MRIL results.

- The 2DFC-T2D analysis indicated the viscosity of hydrocarbon varying from 30 to 100 cp, appeared to be heavy oil.

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