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RESERVOIR QUALITY VARIATION ANALYSIS OF ASMARI-BANGESTAN SECTION USING MRI LOG, AHVAZ OILFIELD, SW IRAN

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Abstract

Reservoir management needs to evaluate accurately the measurements related petrophysical characteristics. This paper presents an effort to describe T2 distribution and the factors affected on it in a section from the Asmari (Oligocene) to Bangestan (Cenomanian-Campanian) reservoirs of Ahvaz oil field, SW Iran. The MRIL log results indicated that the reservoirs are heterogeneous. Effects of the presence of very light oil (condensate) or gas on the T2 distribution were observed through reservoir for multi times. The carbonate reservoir understudy is consisted of tight and permeable zones based on MRIL parameters. The permeability is showing a general decreasing trend and periodic peak pattern. In spite of clay bound water (CBW) distribution and permeability correlation, effective porosity (PHIE) is not indicated a well pattern. The fracture may be involved to increase drastically permeability in upper part. Clay minerals affected as a negative parameter however, its quantity is negligible. It is proposed that the tight horizons (as a thin separator) play an important role in hydrocarbon fluid flow as abnormal pressure. Data indicated that the fluids are not uniform distributed in vertical section of the reservoir.

Keywords: MRIL; Ahvaz oil field; Asmari and Bangestan reservoir; T_2 distribution.

1. Introduction

Petrophysical studies are including determinations of lithology, porosity, permeability, and water saturation for the reservoir intervals. The estimated petrophysical properties such as porosity, permeability, and water saturation from logs which are calibrated with core data and test results, provide a basis for the inference of hydrocarbon potential and the parameters for reserve evaluation [1-2]. Fluid type is the critical factor in many of the decisions that must be made about the fluid from the reservoir [3]. The movement of formation fluids in porous medium is essentially caused by its structural parameters. Numerous attempts to establish analytical connection between permeability and porosity of rocks usually did not give the desired result [4]. Formation evaluation is based mostly on logs, and wireline formation tests [5]. However, researchers have attempted to provide new methods to diagnose and estimate secondary porosity and absolute permeability of carbonate formations based on the numerical simulation (e.g. Sadeq *et al.* [6]).

The petrophysical parameters are determining the reservoir characteristics and field management [7-9]. Conventional or tight/ultra-tight reservoir classification depends to permeability values [10-11]. The importance of reservoir quality study to evaluate the pay zone was discussed [12-14]. These studies resulted to this point that the prediction of factors controlling the quality is the successful key of any program related to the field development. In this direction technical advances will be affected a major role on conventional reservoir development [15-17].

Borehole logs are one of the main tools in order for recognizing the petrophysical characterization of reservoir by which one can obtain petrophysical parameters of reservoir such as shale size, effective porosity, water saturation, permeability, lithology, and comparison of wells. Porosity and permeability of reservoir rocks are the important physical properties related to storing and fluid conduction in the reservoir. Accurate awareness of these two properties for each reservoir together with fluid properties is required for predicting the further performance of oil field [18]. Among above mentioned specification, the permeability parameter comes with complicated calculation and prediction.

Clearly, it is in our interest to obtain a reliable method for predicting permeability from borehole measurement. No download measurement can access permeability directly. However, several techniques have been used to infer permeability from borehole tools. These include poroperm cross plots [18-20], principal component analysis [21], cloud transforms [22], neural networks [23], and genetic algorithms [24.

NMR log principles were discussed well and available in literature [25-28]. The NMR has the potential of differentiating between low resistivity contrast oil and water bearing zones. The logs offer a viable alternative to downhole fluid sampling for determining viscosity information in heavy-oil reservoirs [29-33]. As a general category, there are two wireline tools using different magnet and coil configurations generated as Numar's mandrel device (MRIL or Magnetic Resonance Imager Logging) and Schlumberger's skid design (combinable magnetic resonance (CMR) tool) which was commercially started in 1991 and 1995, respectively [34]. MRIL is revolutionizing the openhole logging business through direct measurement of reservoir fluids such as oil, gas, and water using CPMG tool. In comparing to other tools, CPMG sequences repeated every 20 ms, which is a simulation of the EPM mode on the CMR- B tool [35-37]. It is noticeable that in carbonate reservoir, CMR interpretation is not always straightforward and normal acquisition parameters are not necessarily sufficient to produce data relevant to the task at hand. For instance, under normal reservoir conditions, the oil signal and the water signal cannot be differentiated in most carbonates [38]. The operator acquired both CMR and conventional log measurements due to uncorrected density porosity of conventional logs [39]. MRIL data imparts information about porosity, pore size, bound water, fluid types and permeability.

In the present study MRIL data of one of boreholes of Bangestan reservoir (Az-100) in Ahvaz oil field is analysed in view of different aspects.

2.Geology and description of Ahvaz oil field

Ahvaz oil field (Fig. 1) is one of giant oil filed in Dezful Embayment having three reservoir including Asmari (Oligocene), Bangestan (Cenomanian-Santonian), and Khami (Neocomian-late Aptian). The Bangestan reservoir comparing to other locations have better quality. Dezful Embyment is a part of Zagros fold belt (Pliocene) in the nourth east of Arabian Plate [40-41]. Thickening of this area caused by collision between Central Iran and Arabic plate [42-46]. The field extended for 65 km and 4-6 km at the top of Bangestan reservoir.

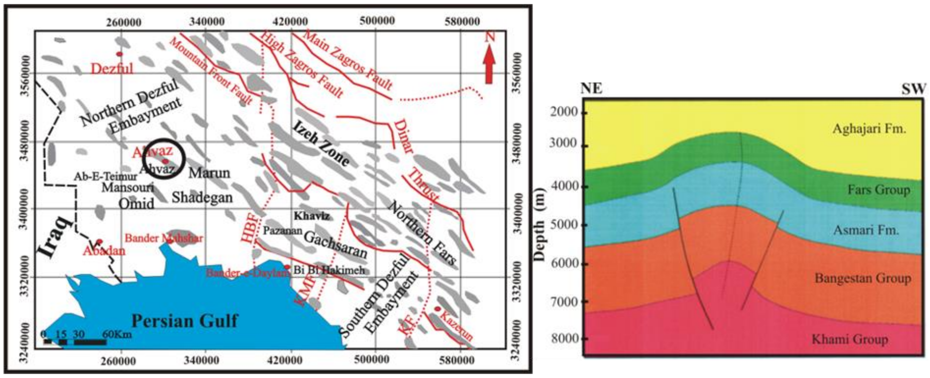

Fig. 1. Geographic position of Ahvaz oil field (Sherkati and Letouzey [82]) and crossed section of the reservoir

Different aspects of Dezful Embayment as an interested tectonic situation were studied as separation and folding of the Phanerozoic sedimentary [42,47-48], Zagros Precambrian basement [48-53] and petroleum prospects [54].

Lithologically, the Asmari reservoir consisted of limestone, and sandstone. Bangestan reservoir consisted of limestone, shale (in very low quantity individual in upper part), and dolomitic limestone. Pabdeh and Gurpi formations with the lithologies of limestone, marl and shale are formed the section between these reservoirs. The oil field was limited by two faults which are detected by seismic traces in upper part of the Bangestan reservoir.

3. Methodology

To estimate the permeability as the basic factor of reservoir quality and production management, it is necessary to find a way based on available data of a borehole logs. Well logs such as caliper (CALI), gamma ray (GR), neutron porosity (NPHI), density (RHOZ), sonic (DT), resistivity (RL) are commonly used. The present work is focused on Magnetic Resonance Imager Log (MRIL; mark of Halibertun) that is now widely used. This tool (advanced version) is equal to Nuclear magnetic Resonance (NMR) log.

NMR tools generally measure the transverse relaxation time T_2 decay time for hydrogen nuclei present in the pores of reservoir rock to realign their spin axes with a magnetic field after momentary reorientation by specific radio frequency (RF) pulses [55-56]. The decay time is obtained by inversion of the echo train data and related to the pore size distribution and one thus can estimate the capillary bound water volume. NMR logging tools has also been improved and overcome technically the slow logging speed and the precision of the total porosity measurement and sensitivity limit. Although the new acquisition sequence and processing algorithm developed and applied to the previous generation of NMR tools. As a limitation that it is unavailable everywhere and not interested.

Understanding the processes that contribute to MRIL relaxation provides the model for extracting petrophysical parameters from MRIL data. Magnetic Resonance Imaging is a more complex application of NMR in which the geometric source of the resonances are detected and deconvoluted by Fourier transform analysis.

4. Data processing

a)MRIL Log Quality Control:

Quality control is essential to obtaining accurate information for the MRIL log. A system of tool- integrity and log quality indicators is used to ensure the highest level of data quality. The MRIL quality-control procedure (Fig.2A) includes calibration, verification (before-survey and after survey), operational setup, log recording, display of quality indicators, and a final quality check. Fig. 2 is an example of log quality display for dual-TW logging. Checking the log, noise features and Chi. All the indicators for Groups A and B at Frequencies 1 and 2, are within their allowable ranges. B1 and B1mod vary with the GAIN changes. B1mod should be further checked against the shop calibration report and must be within 5% of the peak value of the CPMG pulse found during calibration. Cable speed is about 6 ft/min. This speed and running average should be checked with speed chart according to gain, TW and vertical resolution. Raw echo data and T_2 distributions can also be displayed at the well site for quick look and quality check (Fig. 2B)

Gain and Q Level- Gain indicates the amount of loading applied to the MRIL tool's transmitter circuit by borehole fluids and formation. Gain is measured in real time by using a test coil (B1 coil) built into the tool. The test coil transmits an RF signal, which is received by the RF antenna. Gain is the ratio of the amplitude of the signal induced in the RF antenna divided by the amplitude of the signal in the test coil. A gain measurement is made as a part of each pulse sequence. Gain is frequency-dependent. The operating frequency of a tool should be set to achieve maximum gain. MRIL activations are designed to run at a certain Q level: high Q, medium Q, or low Q. The gain value determines which Q level to use.

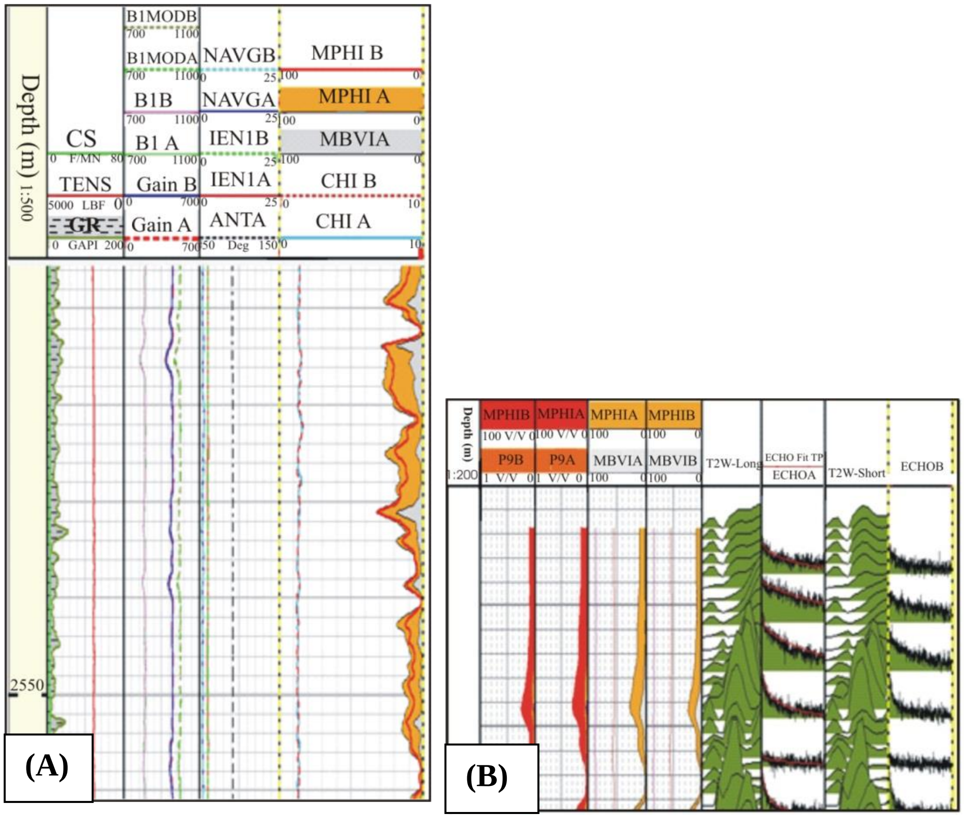

Figure 2. A part of the MRIL log quality display includes Gain, B1, B1Mod, Echo train phase characters, Noise features, Chi, and Measured MPHI and BVI (A); and displays the dual-T_W logging (B)

Chi Parameter- Chi is a measure of the quality of fit between the calculated decay curve and the recorded echo amplitudes. Chi is one of the primary log quality indicators monitored during logging. In general, the value of Chi should be less than 2, but in certain low-Q situations, it may average slightly higher than 2.

MRIL Quality Control – by using Geolog software (version 7.1) was made including check Q level; check B1 field; check noise levels; check signal phase; porosity comparison and generate report and QC plot.

b)MRIL processing, results and interpretation

MRIL data imparts information about porosity, pore size, bound water, fluid types and permeability.

In fluid filled rocks, the volume of rock occupied by fluid is equal to porosity. Petrophysical MRIL measurements utilize hydrogen proton spins to generate a signal. Because hydrogen is abundant in fluids, the magnitude of the MRIL signal is proportional to the formation fluid volume. When all the proton spins are aligned in the magnetic field, the MRIL signal is proportional to the porosity of the rock. Consequently, at the start of the Carr–Purcell -Meiboom–Gill (CPMG) experiment [57-58], at t=0, and before relaxation of the proton spins has occurred, the signal is proportional to porosity. The measurement sequence (CPMG) as a common approach usually consists of several thousands of electromagnetic pulses to enhancing the sensitivity of all measurements in homogeneously-broadened lines [59-60].

MRIL logging tools are calibrated using a 100% porosity reference (i.e., a water filled bucket). The determination of porosity therefore assumes that the hydrogen nuclei in the formation fluid are equal to an equivalent volume of water such that the hydrogen index is 1. Porosity estimates must be adjusted to reflect variation in the hydrogen index of the formation fluid (Fig. 3A). MRIL porosity is independent of matrix minerals, and the total response is very sensitive to fluid properties [61] (Fig. 3B).

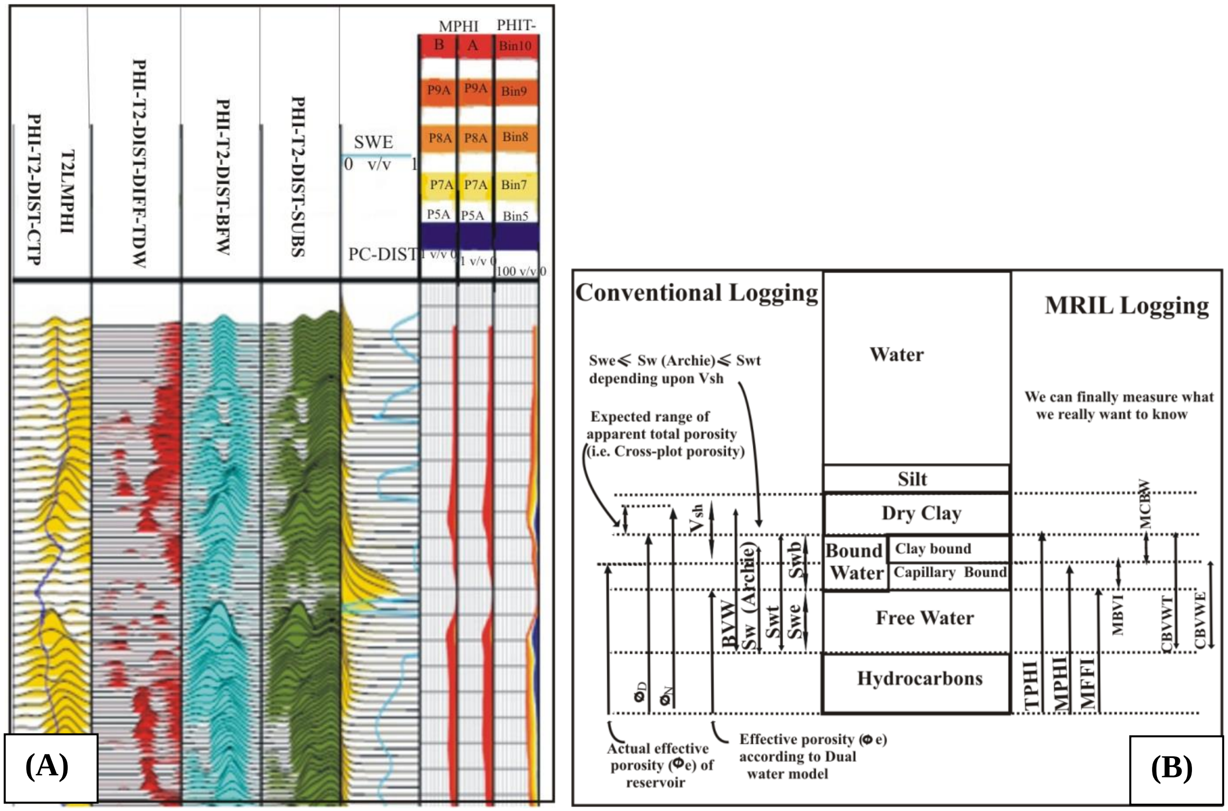

Fig. 3. Porosity distribution and $T_2$10 bins (A) that the number of T_2 bins determines the number of time constants between the minimum and maximum time values which are logarithmically equally spaced; (B) Comparison between MRIL responses and conventional logging (modified after Coates *et al.* [61])

T_2 distribution

The distribution of exponentials, or T_2 distribution, can be interpreted in terms of pore size and the composition of the fluid residing in the pore. When the rock is saturated with a single fluid phase, the T_2 distribution can be interpreted in terms of pore size. As described in surface relaxation, the T_2 value of a single pore is proportional to the surface-to-volume ratio of the pore. Small pores have shorter T_2 relaxation and consequently, the first part of the T_2 distribution corresponds to capillary bound water or bound fluid. The upper part of the T_2 distribution contains free or movable fluid.

T_2 decay is due to irreversible dephasing which occurs in three ways:

1. Surface relaxation, which is due to the interaction of the proton spins with the surface of the pores.
2. Bulk fluid relaxation, which is due to molecular interactions in the fluid.
3. Molecular diffusion, which is due to the diffusion of the molecules along magnetic gradients.

All three of the processes act in parallel and therefore, the T_2 of the pore fluid is given by:

$$\frac{1}{T_2}=\frac{1}{T_{2bulk}}+\frac{1}{T_{2surface}}+\frac{1}{T_{2diffusion}}$$

where: T_2 = transverse relaxation; T_{2bulk} = bulk relaxation of the fluid; $T_{2surface}$ = T2 due to surface relaxation; $T_{2diffusion}$ = T_2 due to diffusion processed.

The T_{2LM} is the geometric mean of the T_2 distribution. This parameter is used for calculating the mean pore size and is used in permeability equations. The T_{2LM} is computed by averaging the logarithms of the relaxation times in the distribution each weighted by its signal amplitude (Fig. 3).

The tool excites a regular pulse sequences with T_E = 0.9 ms, collecting 500 echoes (T_{2L}). This is immediately followed by 20 short CPMG sequences with 10 echoes and a short recovery time of 20 ms (T_{WC}=waiting constant).

The Shifted Spectrum Method (SSM) is a qualitative technique used to represent the changes in the T_2 values of fluids, and hence changes in their T2 distributions, when different echo spacing's (T_E) are used. Consider a formation that contains fluids composed of water and medium-viscosity oil. The diffusion coefficient for water is about 10 times larger than that for the medium-viscosity oil. When T_E is increased, the diffusion process will decrease the T_2 of water more than the T_2 of oil. Long and short-T_E values (T_{EL} and T_{ES}) can be selected so that the reduction in water and oil T_2 values measured with T_{EL} relative to those measured with T_{ES} can be used to separate the water signal from the oil signal. Comparison of the T_2 distributions determined with T_{EL} and T_{ES} demonstrates the relative diffusion-induced shifts of the water and oil T_2 values (Fig. 4).

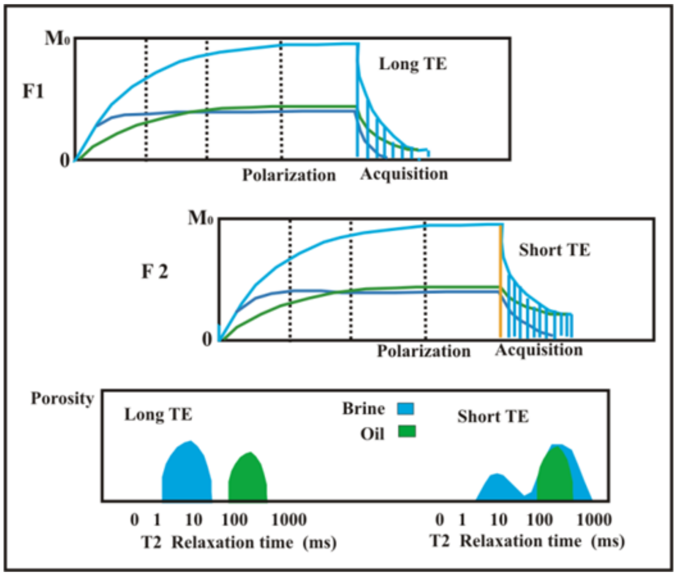

Fig. 4. Dual-T_E logging acquires two fully polarized echo trains, one from a long-T_E measurement and the other from a short-T_E measurement.

Capillary pressure

From a theoretical standpoint, the T_2 distribution provides a distribution of pore sizes of the rock [1,81]where:

$$1/T_2= (S/V)_{pore}+1/T_{2,B}$$

where: T2=relaxation time; S/V=surface to volume ratio; ρ=the relaxivity, typically for natural porous matrices the magnitude of ρ ranges between 1 and 10 μm s^{-1}; $T_{2,B}$=is the relaxation of the bulk fluid.

Consequently, the T_2 distribution can be converted to a pore size distribution [62] and, using the Washburn equation, the pore size distribution can be used to construct a pseudo-capillary pressure curve for each T_2 distribution in the log.

$$Diameter(\mu m) = \frac{C\gamma - 4\cos\Phi}{Pc}$$

where: C=Washburn constant; γ= surface tension; φ= advancing contact angle and Pc= intrusion pressure.

Averaging the pseudo-capillary pressure curves over specific reservoir intervals allows the opportunity to construct J-functions and saturation height functions for a particular interval in the reservoir (Fig. 5A). The T_2 of the gas is concentrated at about 60ms, and the T_2 of oil-based mud filtrate is at about 200ms. The signals from both gas and oil-based mud filtrate will remain in the differential spectrum (Fig. 5B).

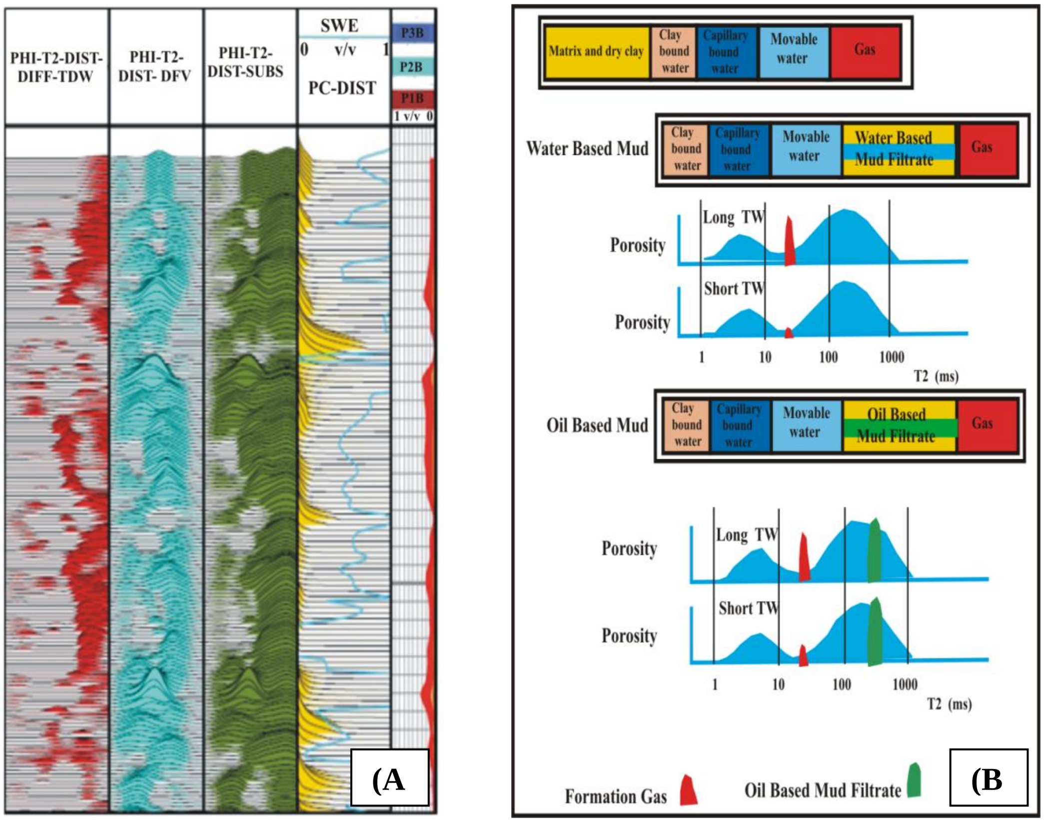

Fig. 5. PC distribution in track 4 (A), and (B) In a gaseous or very light oil (condensate) reservoir zone, the virgin zone contains mud filtrate by oil-based mud

When dual-T_W measurements are used, and the resulting T_2 distributions are subtracted from one another, the water component will be eliminated, and part of the gas component will remain in the differential spectrum. The amplitude of the partial gas component in the differential spectrum will be highly dependent on both the difference between T_{1gas} and T_{1w} and the difference between T_{Wshort} and T_{Wlong}. Normally, logging parameters are set so that $T_{Wlong} \geq T_1gas$ and $T_{Wshort} \geq 3T_{1w}$. In addition, when gas is present, hydrogen index and polarization effects must be considered because gas has low hydrogen index and long T_1. If oil- based mud is used, a signal from the oil-based mud filtrate appears on the T_2 distribution. In figure 6, the effects of hydrocarbon on T_2 distribution is indicated.

Based on petrophysical interpretation results, the formation lithology is carbonate and sandstone. T_2 cutoff 33ms and 100ms were used separately in sandstone and carbonate in MRIL-P processing. Hydrocarbon in whole log interval was detected (oil zone). The results indicated that the processing of MRIL is strongly affected by oil based mud in hole.

Permeability

NMR logging can provide an indirect and discontinuous measurement of permeability by calculating the formation-permeability estimation from the spectral-porosity measurements. Different permeability models have been developed on the basis of combination of empirical and theoretical relationships. Two of them are commonly used [63-67]: (1) The mean-T_2 (Schlumberger-Doll-Research or SDR) model; and (2) The free-fluid (Timur-Coates or Coates) model. However, Timur-Coates model is most common in carbonate [68] and also tight sandstone reservoirs [67]. Nevertheless, these both models are discussed here:

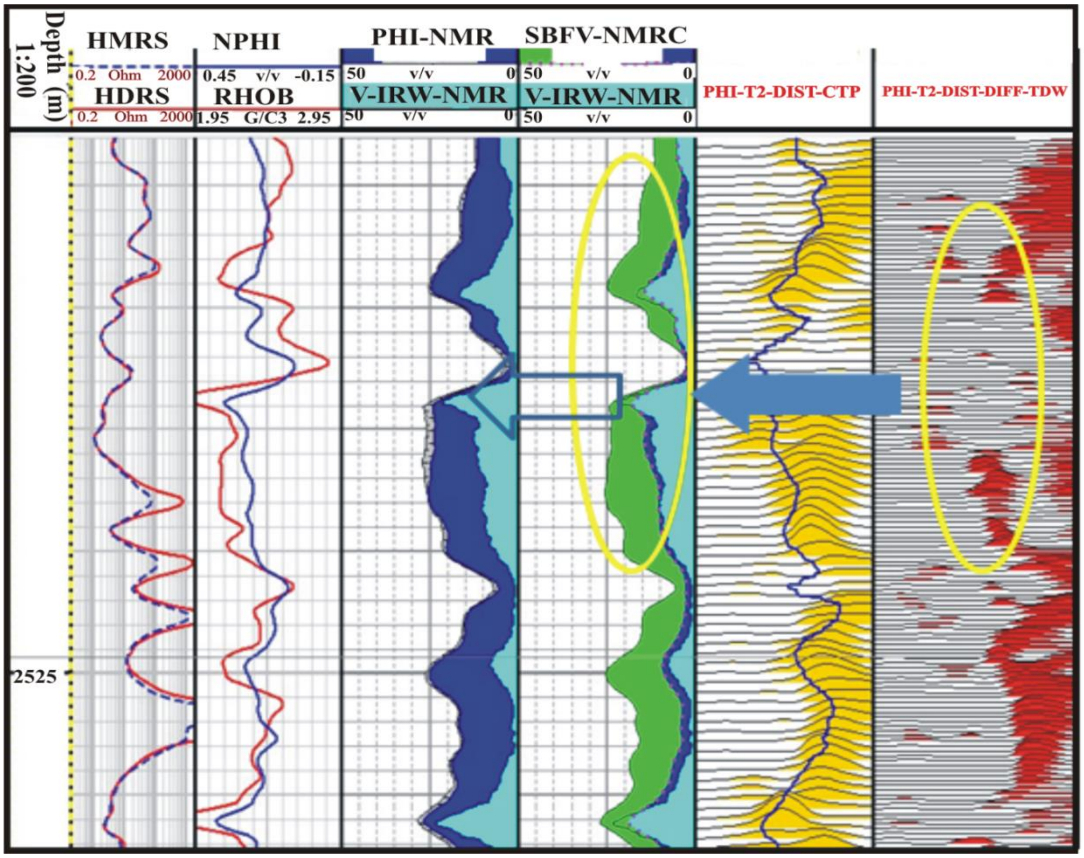

Fig. 6. The effect of the very light oil (condensate) or gas reservoir on the T_2 distribution on track 6. *Abbreviations: Bound fluid water (BFV)–clay bound water (NMRC)= Capillary bound water; HMRS=Medium resistivity; HDRS=Deep resistivity*

SDR model:

In this model, there is used logarithmic mean of resting time, T_2, as a parameter for calculating the permeability. Some complications of this model are in its sensitivity to hydrocarbon (particularly light oil and gas) (Fig. 7A). Because the resting time of hydrocarbon to some extent is different from water, therefore it will influence on logarithmic mean time T_2 (T_{2LM}) [69]).

$$K = C_1 T_{2LM}^{a1} \Phi_{NMR}^{b1}$$

where; K is permeability; T_{2LM} = mean logarithm of resting time, T_2; φ_{NMR} =NMR porosity (V/V); C1, a1, b1 = coefficients.

These coefficients have specific values that for each formation must be obtained by core permeability data [70]. The results indicated that the estimated permeability values are higher than other methods (Fig. 7).

Timur/Coates model:

Timur [71] suggested the relationship for estimating permeability of sandstones from in situ measurements of porosity and also residual fluid saturation obtained from nuclear magnetism log. This work was expanded [72] and compared with other models [73]. The model was expressed as:

$$K=a\ \phi^b\ S^2_{wi}$$

Coefficients *a* and *b* were determined statistically. Then it was improved for effective porosity of NMR [74]:

$$K=a\ .\ [\phi^2_{NMR}\ (FFI/BVI)]^2 \text{ or } K=(\Phi_{NMR}\ /\ C_2)^{a2}\ (FFI/BVI)^{b2}$$

where: FFI=free-fluid volume; BVI= bound volume irreducible; φ_{NMR}=NMR; porosity (p.u.)=FFI+BVI; C2, a2, b2 = coefficients (C is a formation scaling factor that is conventionally set at 10; a and b are exponents whose are default values are four and two, respectively).

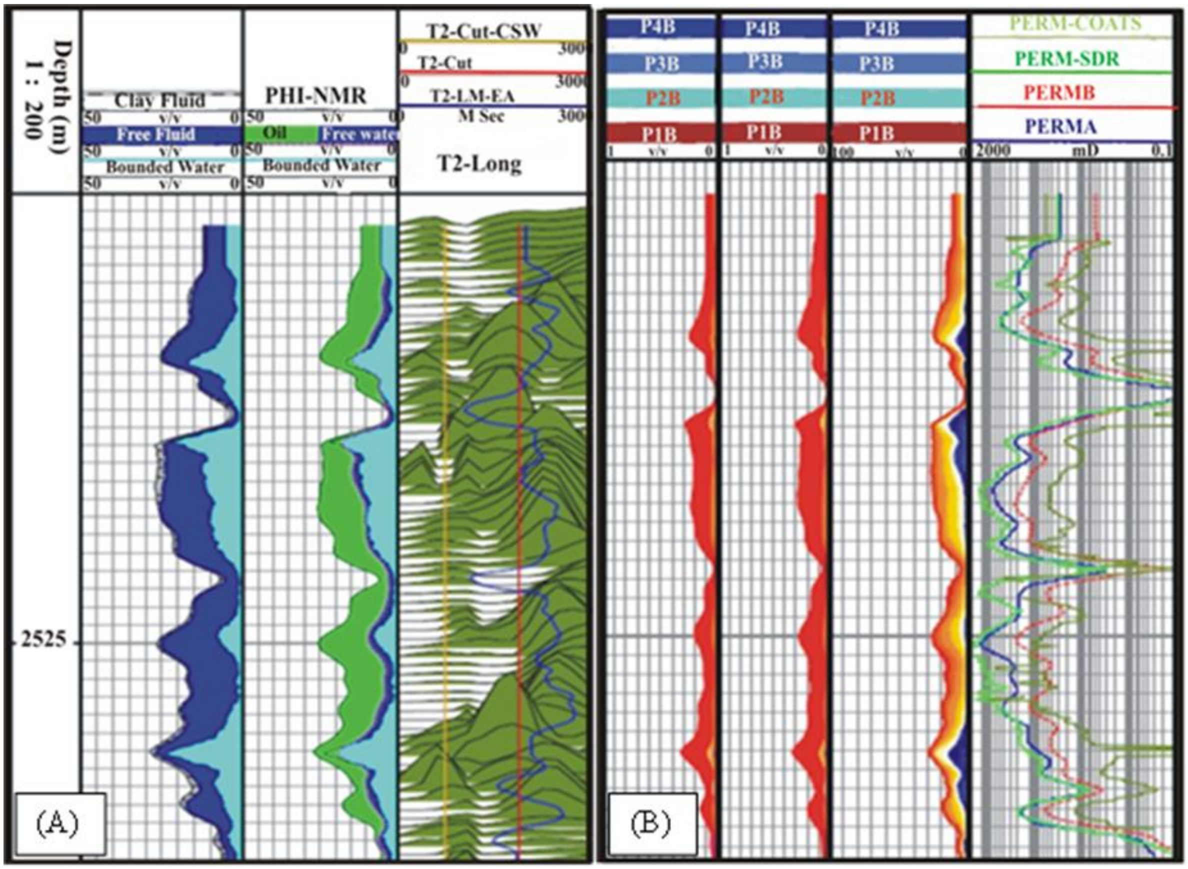

Fig. 7. T2 distribution, clay, irreducible, oil and free water (A), and (B). Coats and SDR permeability

The coefficient values are commonly set so that c1=4, a1=2, b1=4, c2=1, a2=2 and b2=4. The coefficients c, a and b can also be adjusted to match core permeability data. Coefficients a and b are usually determined using NMR core analysis data. Because of differences between the laboratory and the wireline measurement, C, which is used to scale the estimate in milidarcy, is often determined by the log until there is a good match with core permeability (Fig. 7B). In respect to comparing with the core data, therefore, this model is preferred for the carbonate reservoir.

All of these methods rely on mathematical pattern recognition, a simplifying assumption, or calibration to a data set from a different formation in a different field which if often not even the same lithology.

Using core samples of production zone and measuring their permeability under the reservoir conditions is one of the oldest methods for predicting the permeability. Although coring is cost expensive and complicated but valuable information can be inferred from permeability measurements. Due to increased cost of coring method of course it is only possible reduced number of well tests in any field. Therefore, the main reason for the reality of using petrophysical logs is that the cost of processing is very cheaper than coring which is based on a continuous record from the properties of rocks in the well [75].

Information obtained from a drilled well log assists to analysis the heterogeneity degree to use in the parameters calculation and planning of the reservoir.

Therefore, the permeability prediction using MRIL and comparing their results to other conventional well logs are the main objectives of the present research paper (Fig. 8). MRIL permeability results vary between two permeability models and showing a good agreement with core data.

MRIL data results

MRIL chart processing and interpretation (Figs. 8 and 9, Table 1) resulted in main points in the Asmari-Bangestan section of Ahvaz oil field as following herewith:

The reservoirs are heterogeneous and the permeability is indicating periodic pattern but it follows a general decreasing pattern. Effective porosity (PHIE) is also showing some disturbance and not correlated well with the permeability value especially in upper and lower sections (Table 1, Fig. 8). Therefore, the plot exhibits highly varying properties (e.g., porosity, permeability, fluids ratio) within borehole sections of the field, and making them difficult to characterize. Clay bound water distribution trend is interesting. This water does not moveable while flowing fluid through the rock. In fact it is common to consider that this water is not part of the effective porosity and is the residual part of total porosity. In other words, clay-bound water is understood to include the interlayer water. In this case it is consistent with permeability. To decipher the role of parameters in permeability variation, the reservoir can be divided into five parts. As seen in plot 8, ClBW, FW and CaBW are decreased respectively. Therefore, micro-pores are dominant. In second order, large pores (vuggy type) is higher in parts of 1-3 and 5 than small pores, while small pores is dominant in 4th part. It is thus concluded that pore throats is the main factor in controlling of permeability (Figs. 8 and 9) individual in well-developed vuggy zones [76]. However it is observed that PHIE is low in high permeability zones. In spite of low effective value, fracture may also be contributed somehow in upper part. Clay minerals scarcity (very less quantity) in the reservoir is an important which is able to affecting the reservoir quality. However, other parameters such as the presence of clay minerals [77] can be impacted on porosity, permeability, and irreducible water saturation.

Table 1-MRIL interpreted data in the Asmari-Bangestan section, Ahvaz oil field

Formation	Interval (m)	Zones	Mean values					Fluid type
			CapBW	ClBW	FrW	PHIE	Perm	
Asmari (2470-2890)	2501-2530	1	2	12	2	0.24	85	Light oil
	2530-2556	2	1	3	2	0.17	42	O
	2556-2573	3	1	3	1	0.7	4	W
	2573-2591	4	1	5	2.4	15	10	O
	2591-2608	5	0.5	4	2.2	21	74	O
	2615-2663	6	1.5	7.5	2.4	22	48	O
	2663-2712	7	0.2	2.3	2.1	18	61	O
	2712-2782	8	0.9	1.1	20	22	60	W
	2782-2970	9	2.8	3.6	1.2	4.9	0.01	W
Pabdeh (2890-3118)	2970-3050	10	2.7	5.5	0.9	6.6	0.01	W
	3050-3275	11	1	6	0.2	6.2	0.01	W
Gurpi (3118-3255)	3275-3350	12	0.8	2.7	1.3	15	44	O
Illam (3255-3413)	3350-3411	13	0.1	1.5	0.3	7	9	O+W

To explain the reservoir behavior, according to permeability variation, the presence of tight horizons is important. Their function may be as a separator to control the hydrocarbon distribution, increase the confining pressure in permeable zones and so conduit the hydrodynamic pressure and enhance derive mechanism of the reservoir as high as abnormal pressure [78-79]. Although it should be noticed lithofacies changes (mudstone, packstone, dolostone, and shale) have been played a key role in reservoir characteristics. According to these data revealed that several parts tend to act as semi tight/tight zones such as interval of zone 3 in Asmari, pabde-

Gurpi formations and the top and base of Ilam Formation. These zones can be considered in view of abnormal pressure distribution or hydrocarbon prospects for further studies.

The reservoir fluids distribution and other parameters are not uniform in vertical section. This is explained in different intervals.

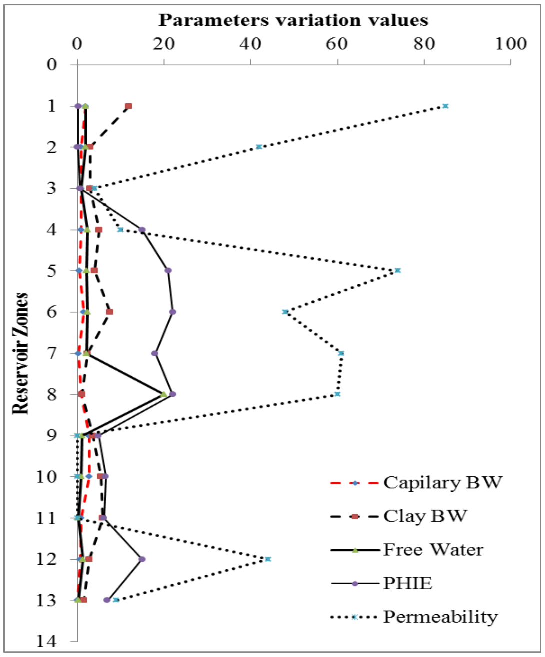

Fig. 8.Reservoir properties variations based on MRIL process

Interval（2501.0-2530.0m）

Based on processing result, average effective porosity is 24%, clay bound water is low (average 2%), and capillary bound water is high that in some interlayers estimated to be about 12%. Oil show was indicated in differential spectrum and based on TDA distribution, the fluid can be very light oil or condensate.

Interval（2530.0-2560m）

There are the same features as interval 2500-2530m in MRIL-P processing chart. The porosity is less than the upper interval. Oil show was also detected in differential spectrum, SW is less than 8%. This interval evaluated as a good oil zone. The permeability is estimated about 44 md

Interval (2573-2712.0m)

In this interval, average effective porosity is in the range of 18 to 22%, clay bound water is low and varies from 0 to 0.9%, and capillary bound water values are 3 to 7%.

T2 spectrum shows the typical single peak which indicates that the formation is pure with uniformity of pore size. Oil shows were recognized in differential spectrum (TDA).

Interval (2712-2782m)

This is the best reservoir section in log interval. Average effective porosity is 20.2 to 22%, clay bound water is low ranging from 0.6 to 0.8%, capillary bound water values are changed from 1.5 to 2.8%. Porosity and pore size is very good with the average of greater than 20%. Although, oil shows were apparently detected in differential spectrum (TDA) and consequently it should be a candidate for very good oil reservoir. But by correlating the results with conventional log observed that RT is very low which is indicated a typical water reservoir. Therefore, it can be concluded that MRIL-P results are affected by oil based mud.

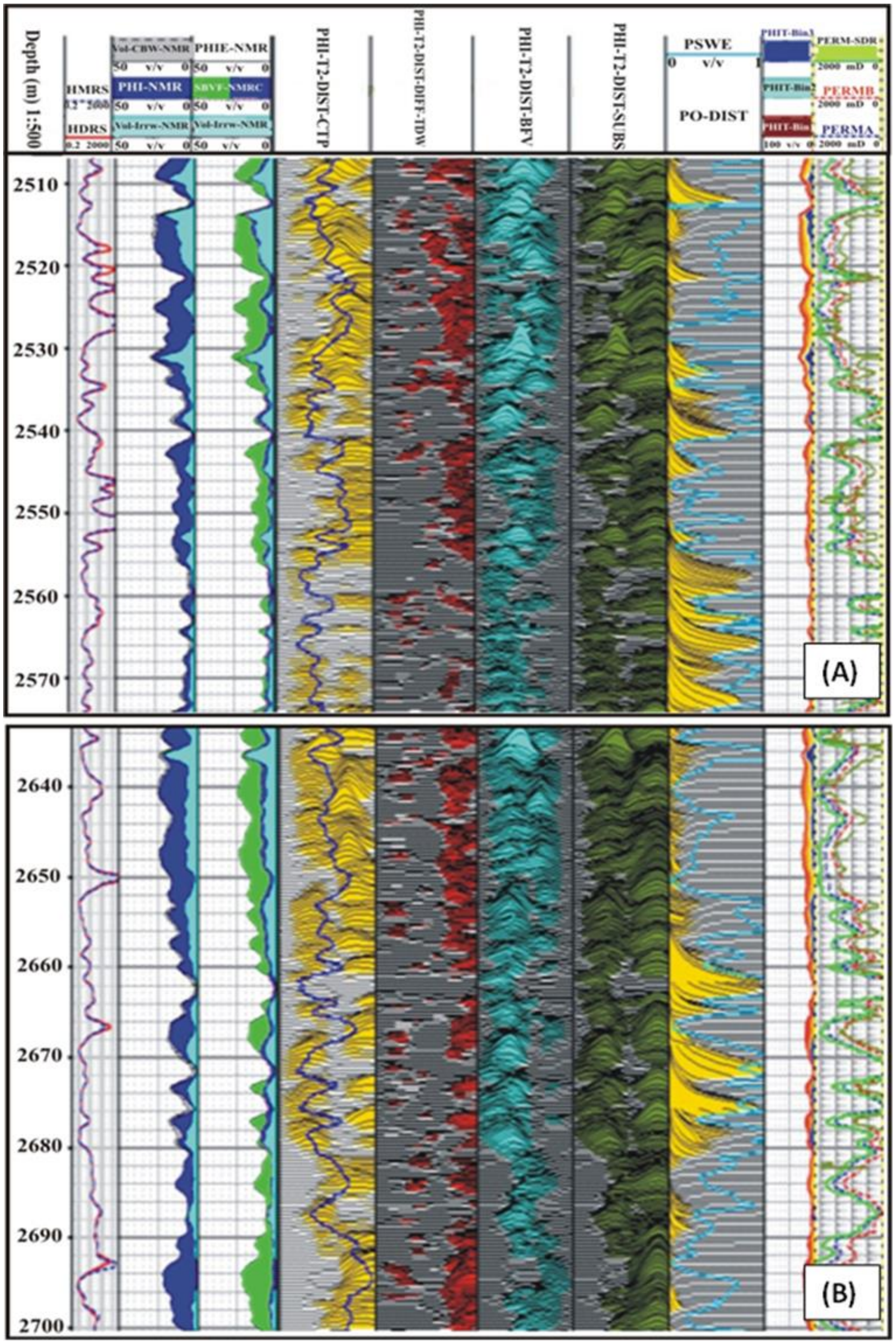

Fig. 9. Final interpreted and processed MRIL plot of the Asmari-Bangeston section, selected zones (well no. Az-100): (A) Zones of 1-3; and (B) Zones of 6-7

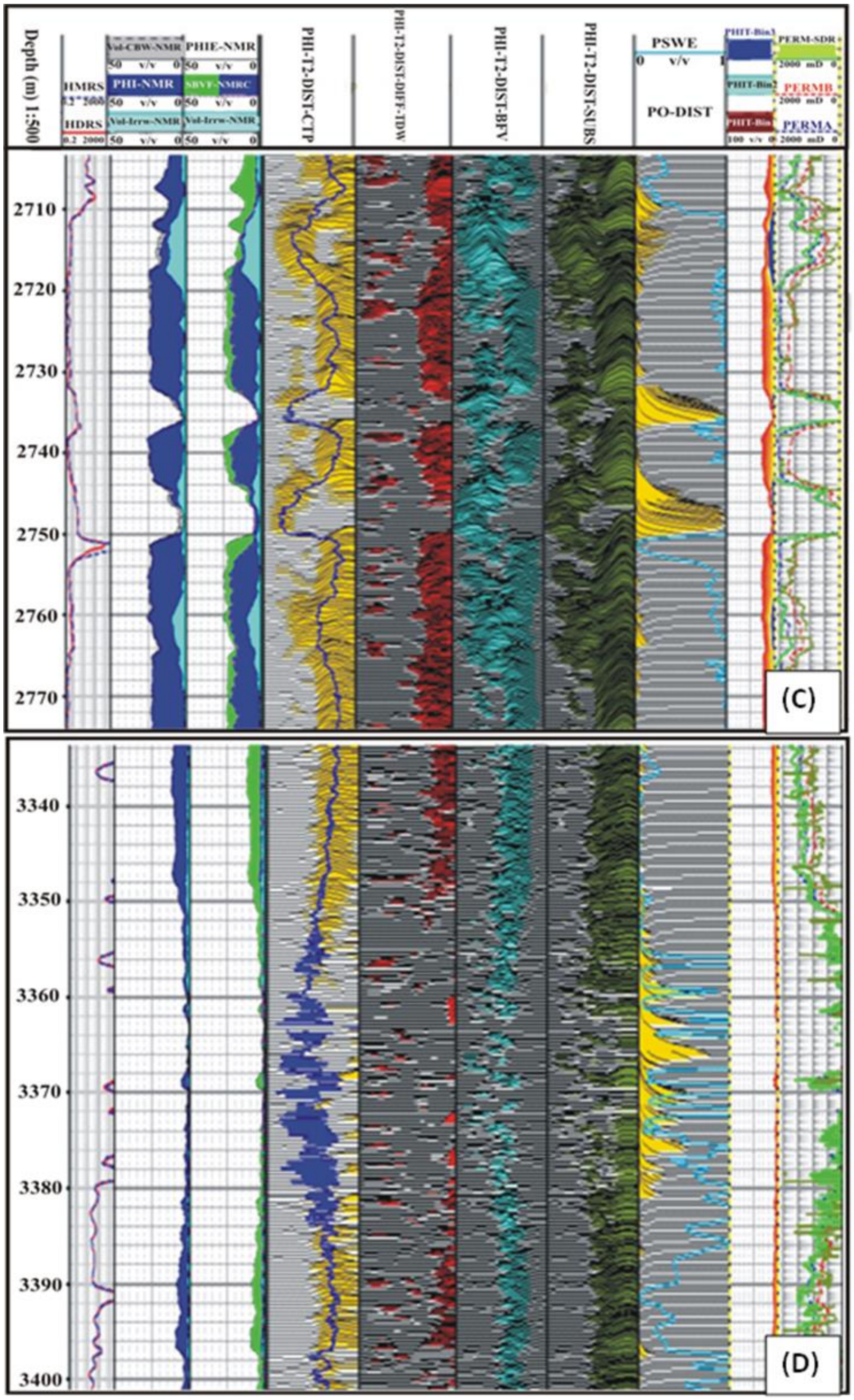

Fig. 9. Continued: (C) Zone of 8; and (D) Zone of 13

Interval (3275-3350m)

In this interval, effective porosity is varied between 9 to 15%, clay bound water is low (in the range of 0 to -0.6%), and capillary bound water values are changed between 1.0 to 3.3%. T2 spectrum shows typical single peak indicating that the formation is pure and its pore size is uniformity. Oil shows were indicated in differential spectrum (TDA). The oil is heavy.

5. Conclusion

Carbonate reservoirs are showing unexpected changes in properties, making them difficult to characterize. MRI logging is a useful tool to evaluate the reservoir behavior. The present paper is an attempt to clarify reservoir variants in the Asmari-Bangestan reservoirs, SW Iran. MRIL data analyses indicated that these reservoirs are heterogeneous, consisted of tight and permeable zones. The permeability is indicating a periodic pattern with a general decreasing trend. Effective porosity (PHIE) is also not correlated well with the permeability. Clay bound water (CBW) distribution is consistent with permeability. The fracture may have been some contribution in upper part. Pore throat is the main controller of increasing the permeability. Clay minerals play a negative effect in the reservoir quality.

The presence of tight horizons is important as a separator to control the hydrocarbon distribution and derive mechanism of reservoirs as an abnormal pressure. The reservoir fluids distribution is not uniform in vertical section. It seems the upper part is preferred in any oil production project (i.e. Asmari and upper part of Bangestan).

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