Measurement of Archie Parameters of Some Carbonate Cores at Full Reservoir Conditions

(Short Communication)

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Abstract

Application of Archie equation in carbonate reservoirs is not easy due to high dependence of its parameters on carbonate characteristics. Carbonates are very heterogeneous in nature and hydrocarbon reserve estimation in these reservoirs of mostly oil-wet and intermediate-wet is highly influenced by the input values of saturation exponent.

To our knowledge, non representative oils have been used in most saturation exponent measurements and not many cases have used live oil for carbonate cores at full reservoir conditions. Performing these experiments at laboratory conditions which differs from reservoir ones would not yield reliable results.

The main effort of this study was to properly measure saturation exponent on some carbonate core plugs of an Iranian reservoir at reservoir conditions using live oil by porous plate technique. Resistivity index and capillary pressure by drainage process on some plugs from pay-zone and resistivity index by imbibition process on some plugs from near and within transition zone of studied reservoir were measured.

Regression fits by using Archie equation were not satisfying. Hence, the regressions were also obtained without taking into account the origin point which insisted the use of a “b” (saturation distribution) factor in the Archie equation.

Keywords: Archie equation, Drainage, Imbibition, Resistivity index, Saturation exponent

Introduction

The measured electrical parameters “a”, “m”, and “n” of porous rocks are basic requirements for the evaluation of fluids saturation and hydrocarbon reserve from resistivity well logs; whatever the type of reservoir. Estimation of hydrocarbon reserves is highly influenced by the input values of “n” especially in non water-wet reservoirs.

Carbonate reservoirs are of great importance, because they contain almost 60% of world`s oil reserves. Great varieties of carbonate rocks exist that are classified based on their lithology, texture and structure. Archie equation [1] is not easy to be applied to carbonate reservoirs, because the electrical parameters are functions of the changes in pore geometry, clay content, tortuosity of the pores, as well as the formation pressure.

The Archie equation is valid only when the rock is strongly water-wet and clay free, which is not the case in most carbonate reservoirs [2]. Pore geometry is often complex and intrinsic heterogeneity and micro-fracturing are very common in most carbonates. Therefore, as many researchers and petroleum engineers believe, the best way is to measure electrical parameters at reservoir conditions using representative core samples and reservoir fluids [2, 3, and 4].

Performing saturation exponent and cementation factor experiments with simulated fluids and even dead crude oil under experimental conditions which sometimes differ greatly from reservoir ones (pressure, temperature, effective stress, fluids and etc.) would not yield reliable results. Longeron [3] obtained different values of “n” using reservoir oil and refined oil.

Anderson [5] stated that with the exception of highly water-wet rocks, the resistivity index-water saturation (RI-S_W) relation is affected by wettability, especially for low values of water saturation. Unless the reservoir is strongly water-wet, the

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value of “n” must be measured with preserved or restored samples at reservoir conditions. Researchers found that using crude oil, results in the higher “n” values than the ones obtained from using refined oil [3]. This is attributed to the wettability changes of the cores in proximity with crude oil. The main impact regarding wettability and the Archie saturation exponent “n” is that using a standard “n” value of 2, when the actual “n” of the reservoir is higher, may produce a significant underestimation of water saturation and an overestimation of in-situ oil volume [6].

Extremely high values of “n” (5 to 10) were obtained from a study by Keller [7] and Sweeney [8] on hydrophobic samples. Scendena et al. [9] in a study on sandstone samples found that Irreducible Water Saturation (IWS) and “n” increase when reservoir conditions are restored. They related the differences to a change in the wettability preference from neutral to oil-wet.

The effect of saturation history (drainage and imbibition) has been also investigated by some researchers like Sanyal [10] and more recently by Wei Jun-Zhi and Lile [11]. They found that drainage/imbibition saturation exponents are not significantly different, except for strongly oil-wet cores. Moss et al. [12] also observed variation of capillary pressure and resistivity indices for the reservoir samples when they are in different states.

Langeron [3] studied the effect of confining pressure on “n” and declared that with respect to the type of rocks, with increasing confining pressure, “n” can be increased and or even decreased. Hence, reliable “n” values can only be obtained at representative reservoir pressure and temperature.

Saturation exponent (n)

The standard method of relating hydrocarbon saturation to resistivity in a clay free rock is based on the Archie’s 1942 methodology known as the "Archie Equation" (eq. 1).

$$S_W = \left(\frac{a}{\varphi^m} * \frac{R_W}{R_t}\right)^{1/n} \qquad \text{(Eq. 1)}$$

The Archie equation is made up of two equations; the “Resistivity Index” (RI) and the “Formation Resistivity Factor”. The Resistivity Index, which can be impacted by many parameters, is defined as:

$$RI = \frac{R_t}{R_o} = \frac{1}{S_W{}^n} \qquad \text{(Eq. 2)}$$

“R_O” is the resistivity of studied rock fully saturated with formation water with resistivity of “R_W”. The Archie saturation exponent “n” in equation 2 is mainly determined by injecting gas or oil into a cleaned, water-saturated rock and measuring core resistivity (R_t) at decreasing water saturations. A log- log plot of RI versus S_W typically yields a straight line with the slope being “-n”. The Archie equation assumes that all the brine in the sample contributes to the flow of electrical current and that “n” is constant for a porous medium. This is generally true in highly water-wet rocks where electrical continuity in brine is maintained down to low S_W values [6].

In the Archie equation RI value at 100% water saturation is treated to 1. This has no basis since the derivation of “n” is a graphical technique, and therefore, empirical. Many intercepts can be found which are not equal to one [6]. This indicates that an adjustable intercept “b” factor is missing in the equation [2]. Some studies [2 and 13] in oil-wet and intermediate-wet core samples and the ones performed in this study showed that “b” has to be added to equation 2 that makes it:

$$RI = \frac{b}{S_W{}^n} \qquad (3)$$

“b” can be called “saturation distribution factor”. It depends on the pore structure, water distribution and wettability [13]. Shamsi and coworkers [2] believe that for many carbonates, assuming a linear relation between resistivity index and formation water saturation is also incorrect.

Capillary pressure resistivity Index (CAPRI) measurement system

The CAPRI system applies porous plate technique that is capable of measuring full cycle capillary pressure curves and resistivity indices as a function of saturation on a core plug sample. The saturation changes in the sample are measured by two HPHT corrosion-resistance pumps, with accuracy better than 0.01 cc, attached to the core holder through semi-porous plates. Unlike the centrifuge, with this apparatus one can obtain direct capillary pressure at reservoir conditions with no use of any interpretation algorithm to convert data to real P_C values.

In this study the resistivity was measured using 4 electrodes terminal technique. Nominal rupture differential pressure of the porous plates was ±150 psi. All data were recorded automatically for further analysis. 4 individual CAPRI systems were used for this study connected to a UPS for removal of electrical current fluctuations and shut-offs.

Reservoir cores and fluids properties

4 carbonate core plugs with diameter of 1.5″ and 2″ long from different zones of a carbonate reservoir in the South of Iran were selected for this study. Samples CP-1 and CP-2 were selected from main pay-zone and samples CP-3 and CP-4 were selected from near and within the transition zone of the reservoir. The properties of reservoir live oil are given in table 1. The properties of the samples are presented in tables 2 and 3, and figure 1 shows their pore size distribution by mercury injection. Dead crude oil of the target reservoir contained high amount of resin and asphaltene, which like many other dead crude oils, would not be appropriate for resistivity index tests.

The experimental setup and procedure

In this study, due to long duration of the tests, “m” and “n” were measured on 4 core plugs at reservoir conditions. In order to use the proper “m” and “n” values for petrophysical studies, selected samples (CP-1 and CP-2) from reservoir pay-zone were undergone drainage process and selected samples (CP-3 and CP-4) from near and within transition zone were undergone imbibition process.

Longeron [3] indicated that “n” values obtained from drainage resistivity index measurement to be used for primary evaluation of hydrocarbon initially in place and in transition zone and flooded areas the “n” values from imbibition measurements to be used. Maute [14] also declared that experimental data are needed to interpret resistivity logs in water flooded reservoir zones and further in S_{xo} calculation.

The experimental tasks included setup and preparation of CAPRI systems, core samples and live reservoir oil preparation, and processes of cementation factor, capillary pressure and resistivity index measurements at equilibrium conditions.

The cleaned plug samples were vacuumed for 2 hours and then were saturated with prepared synthetic brine of 240,000 PPM at pressure of 3000 psig. Fresh hydrophobic and hydrophilic porous plates were saturated by n-Decane and brine, respectively. n-Decane was selected as the oil phase for pressurizing the loaded samples to reservoir pore and confining pressures and temperature. An in-line 5 micron filter was assembled before oil porous plate in order to extract sand, heavy metals and other contaminants present in the live oil cylinder.

The oil pump was set on differential pressure mode to hold constant differential pressure between oil and water pumps. The water pump was set on pressure mode to maintain applied pore fluid pressure. Sustaining a 1000 psig pressure difference between confining and pore pressure pumps, the pore pressure was gradually increased to 4350 psig with the ramp of 10 psi/min. The temperature of air bath oven was increased gradually to reservoir temperature.

In this study it was attempted to apply full reservoir conditions even though some conditions are not as important as others. In a study Scendena et al. [9] concluded that the effect of wettability is more influential than that of pressure and temperature. In the laboratory hydrostatic loading is applied on core plugs, which differs from reservoir loading and causes compaction exceeding reservoir values. In the reservoir, vertical (overburden) pressure differs from the lateral stresses. Hence the average of stresses in the reservoir should be applied hydrostatically on core sample in the laboratory, which is:

$$P_{Hyd.Conf} = \frac{1+\nu}{3(1-\nu)}(P_{Overb} - P_{Pore}) + P_{Pore}$$

(Eq. 4)

Where ν is the Poisson's ratio and is often averaged at 0.30. Considering this ratio equal to 0.30, a coefficient of 0.62 is obtained for conversion of reservoir overburden pressure to laboratory hydrostatic confining pressure. For these samples from true depth of almost 2800m and reservoir fluid pressure of 4350 psig, hydrostatic confining pressure of 6860 psig was applied for this reservoir condition study.

Table 1: Properties of reservoir live oil

Reservoir temperature	196°F	**Calculated oil density @ 4350 psia**	0.8331 gr/cc = 38.3°API
Saturation pressure	1071 psia	**Reservoir pressure**	4350 psia
Calculated oil viscosity @ 4350 psia	5.4 cp	**Nickel, Vanadium, Iron, Lead and Sodium contents**	≈ 186 PPM
Asphaltene and Wax content of stock tank oil	13 %Wt	**Separator gas H_2S**	1750 PPM

Table 2: Water-Oil Resistivity Index Measurement at Reservoir Condition (Drainage Process)

Sample Properties	$(P_{Oil} - P_{Water})$, psig	Days for Stability	R_t(Ohm)	S_w	RI	n
Sample ID: **CP-1** Archie`s Classification: II, A/B Porosity (%): 23.09, Air Permeability (mD): 14.586 Rw @ test condition (Ohm): 0.023, m=**1.90** Average "n" from forced fit to pass RI=1 @ Sw=1.0: **1.882** Average "n" not taking into account RI=1 @ Sw=1.0: **1.698**	-5.0	3	0.3720	1.0000	1.00	—
	10.0	23	0.7932	0.6842	2.13	2.00
	30.0	13	0.9456	0.6042	2.54	1.85
	70.0	8	1.0487	0.5683	2.82	1.83
	110.0	24	1.2011	0.5400	3.23	1.90
	Total Days: 71					
Sample ID: **CP-2** Archie`s Classification: I/II, A/B Porosity (%): 14.28, Air Permeability (mD): 1.404 Rw @ test condition (Ohm): 0.023, m=**2.39** Average "n" from forced fit to pass RI=1 @ Sw=1.0: **1.677** Average "n" not taking into account RI=1 @ Sw=1.0: **1.293**	-5.0	3	2.4175	1.0000	1.00	—
	10.0	14	15.2546	0.4193	6.31	2.12
	30.0	19	26.4948	0.2542	10.96	1.75
	70.0	24	61.5090	0.1349	25.44	1.62
	110.0	11	78.7708	0.1193	32.58	1.64
	Total Days: 71					

Table 3: Water-Oil Resistivity Index Measurement at Reservoir Condition (Imbibition Process)

Sample Properties	$(P_{Oil} - P_{Water})$, psig	Days for Stability	R_t(Ohm)	S_w	RI	n
Sample ID: **CP-3** Archie`s Classification: II, A/B Porosity (%): 21.99, Air Permeability (mD): 1.788 Rw @ test condition (Ohm): 0.023, m=**2.03** Average “n” from forced fit to pass RI=1 @ Sw=1.0: **2.658** Average “n” not taking into account RI=1 @ Sw=1.0: **1.576**	-5.0	3	0.5004	1.0000	1.00	—
	110.0	68	2.6224	0.5176	5.24	2.52
	-5.0	8	2.2159	0.5685	4.43	2.64
	-30.0	18	1.7155	0.6759	3.43	3.15
	Total Days: 97					
Sample ID: **CP-4** Archie`s Classification: II, A/B, vugs Porosity (%): 25.06, Air Permeability (mD): 20.853 Rw @ test condition (Ohm): 0.023, m=**1.99** Average “n” from forced fit to pass RI=1 @ Sw=1.0: **1.794** Average “n” not taking into account RI=1 @ Sw=1.0: **0.682**	-5.0	3	0.3615	1.0000	1.00	—
	110.0	59	1.0666	0.4927	2.95	1.53
	-5.0	7	0.9729	0.5798	2.69	1.82
	-20.0	13	0.8747	0.6642	2.42	2.16
	-90.0	7	0.8033	0.7505	2.22	2.78
	Total Days: 89					

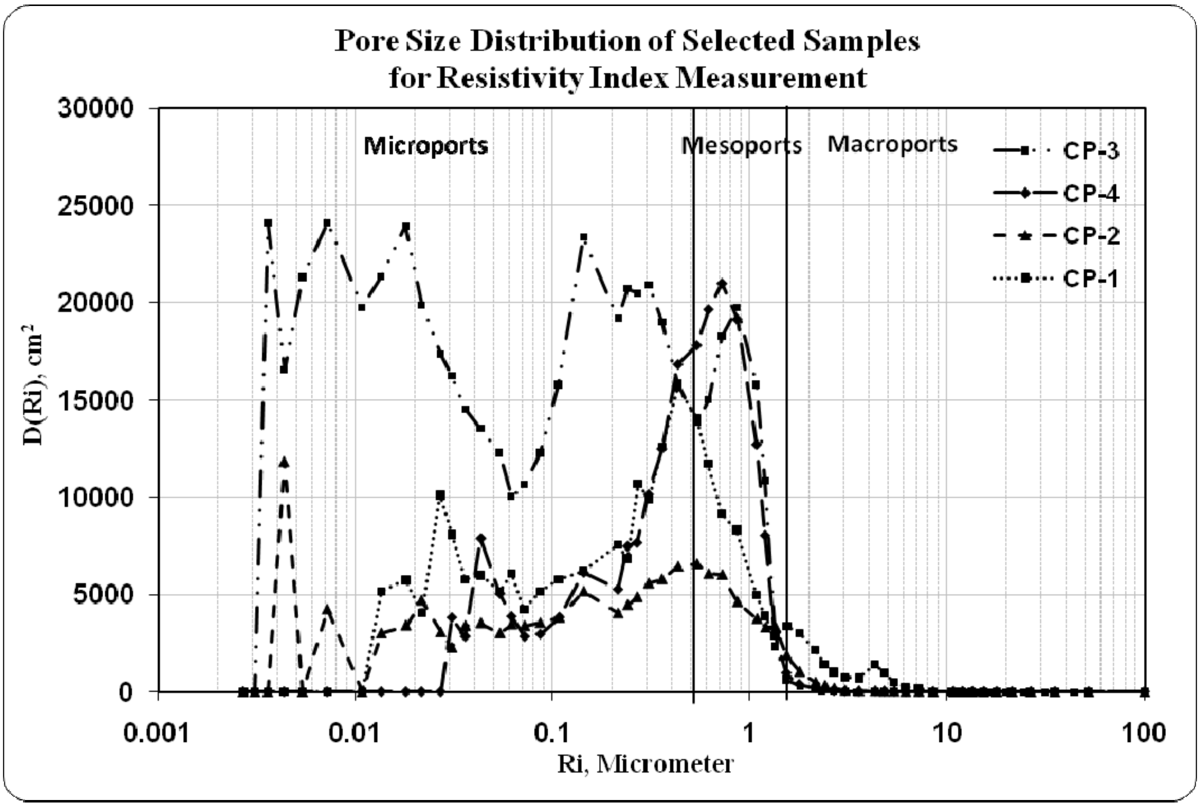

Figure 1: Pore size distribution of selected samples from mercury injection method

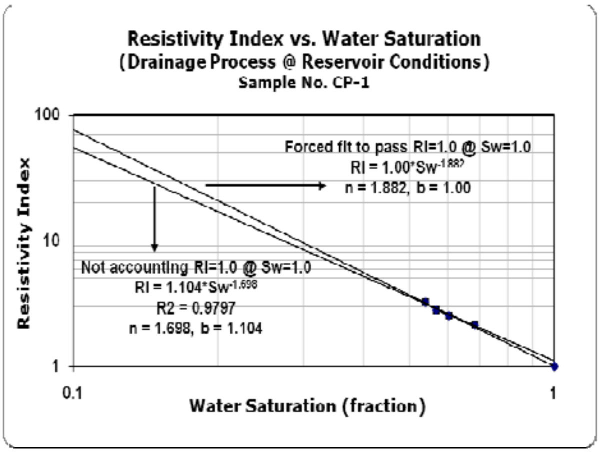

Figure 2: **measured resistivity index values vs. water saturation of sample CP-1 from drainage process and two fitted regression curves**

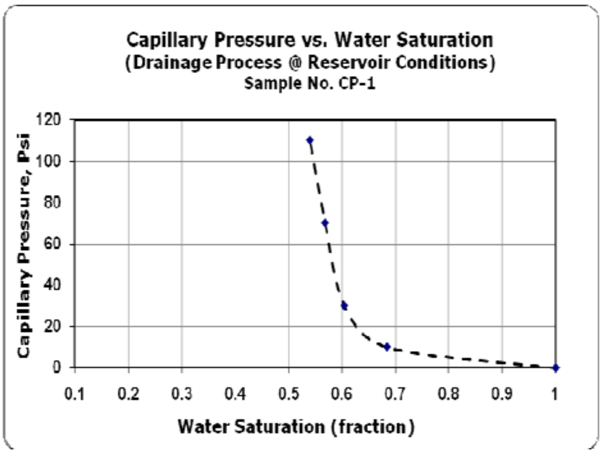

Figure 3: measured drainage capillary pressure vs. water saturation of sample CP-1 at reservoir conditions

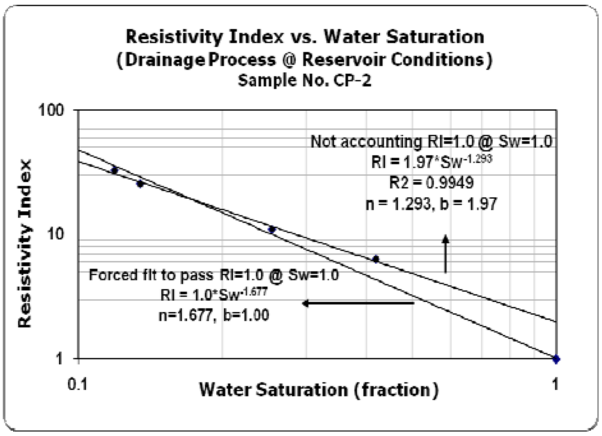

Figure 4: measured resistivity index values vs. water saturation of sample CP-2 from drainage process and two fitted regression curves

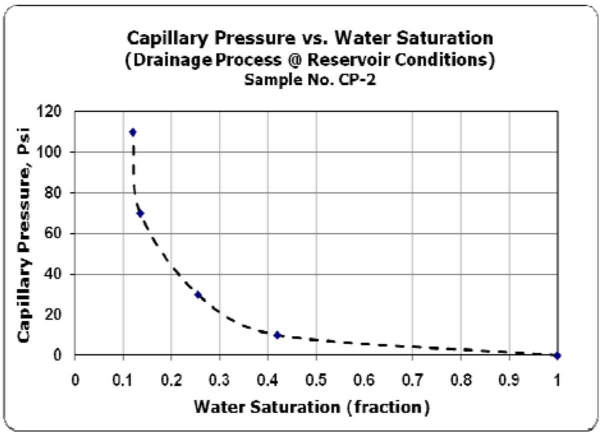

Figure 5: measured drainage capillary pressure vs. water saturation of sample CP-2 at reservoir conditions

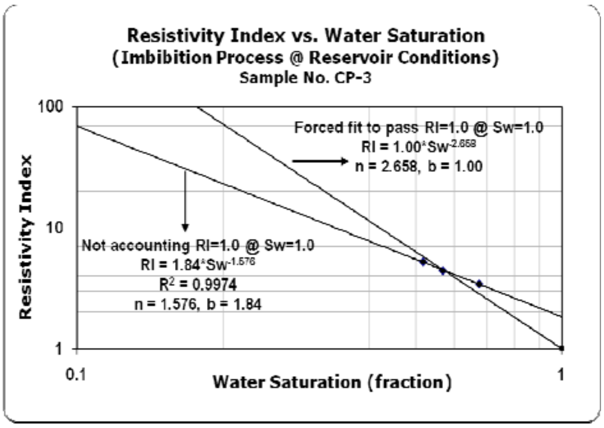

Figure 6: ation of sample CP-3 from imbibition process and two fitted regression curves

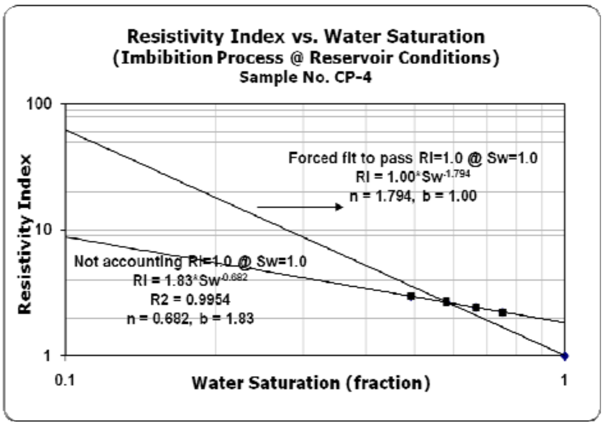

Figure 7: measured resistivity index values vs. water saturation of sample CP-4 from imbibition process and two fitted regression curves

When the system was established to reservoir pressure and temperature conditions, n-Decane was removed by pre-heated live reservoir oil through a micro valve at 4300 psig pressure. Enough oil was allowed to pass and completely remove n-Decane in the oil pump and connected lines. The samples were allowed to reach equilibrium with brine at reservoir pressure and temperature under differential pressure of -5 psig ($P_C = P_{oil\ pump} - P_{water\ pump}$) for 3 days for obtaining "R_O". Cementation factor of samples was then calculated from Archie equation.

For applying a capillary pressure in the experiments with porous plate one should make sure of good capillary contact between plug and porous plates. In this study, in addition to putting paper filters between porous plates and core end-faces, the core plug faces were machined to have end surfaces exactly perpendicular to the core axis.

Conventionally drainage resistivity index measurement is performed to obtain "n" values in equation 2. Samples CP-1 and CP-2 were undergone drainage process. We continued the tests long enough (table 2) to reach stability as Longeron [3] concluded that carbonate rocks need more time to reach equilibrium. Due to long duration of the tests, capillary pressure was increased in 5 steps. ±0.02 cc/day was our criteria for stabilization of fluids volume in injecting/receiving pumps.

Samples CP-3 and CP-4 were undergone imbibition process in which water was injected into aged plug samples at irreducible water saturation (IWS) condition. The stabilization in IWS and "R_t" lasted 68 and 59 days for samples CP-3 and CP-4 respectively. Due to long duration of the tests, the capillary pressure was decreased in limited steps (table 3).

The effluent water and injected oil in drainage process, effluent oil and injected water in imbibition process and measured true resistivities of core samples and brine cells were recorded continuously in daily history files.

The average value of "n" was calculated from the slope of resistivity index curve versus equilibrated brine saturations firstly passing through the origin (RI = 1, $S_W = 1$) and secondly without taking into account the origin point on the logarithmic scale (tables 2 and 3, and figures 2, 4, 6 and 7). These tests showed that the origin point with R_t equal to R_O which some factors like wettability are not implied, should not be used in regression.

Experimental results and discussion

In Archie equation it is assumed that water saturation is distributed uniformly throughout the sample, and that the saturation exponent is constant over the saturation range. However, in many cases and in this study, measured "n" values are changing with different established water saturations (tables 2 and 3).

Minimum IWS`s of 54.00%, 51.79% and 49.27% were established in the samples CP-1, CP-3 and CP-4, respectively. The high IWS could be due to incomplete capillary continuity between core end faces and the porous plates and limited maximum differential pressure of 110 psig. However, due to long duration for each test step, the results are reliable. The wettability of nearby core plugs from USBM technique using dead crude oil showed oil-wetness characteristics.

Some researchers believe that the saturation exponents measured at the onset of imbibition resistivity index tests provide the most reliable "n" values as they are determined on restored samples prior to any hysteresis that occurs during increasing water saturation [6]. The "n" values of 1.90 and 1.64 were obtained from samples CP-1 and CP-2 and 2.52 and 1.53 from samples CP-3 and CP-4 respectively at IWS conditions.

Samples CP-1 and CP-2 do not show a large increase or decrease of measured "n" values during drainage process; however "n" increased at IWS. The shape of the RI profile during imbibition will principally be controlled by wettability and pore geometry [6]. The measured "n" values from imbibition process on samples CP-3 and CP-4 are increasing with water saturation decrease, which "n" was almost doubled in sample CP-4 at the end point. Anderson [5] indicates 2 reasons for sharp increase of "n" values in carbonate rocks, partly trapping the water in the oil and fingering of water. Wei and Lile [11] stated that "n" in oil-wet rocks is highly affected by direction of saturation changes.

Pore size distribution (PSD) of studied samples is presented in figure 1. Mainly pore sizes are in the range of micro and meso ports. Sample CP-1 has bimodal shape with variety of pore throat sizes ranging from micro to macro. Sample CP-2 has polymodal shape with variety of pore throat sizes ranging from mostly micro to macro. These could be a reason for not having high values of "n" for these samples, though USBM tests showed oil-wetness characteristics. Some reservoirs might be hydrophobic yet conductive through the bond water that exists within the matrix. This situation tends to lower the value of "n". The value, nevertheless, should be high [15].

Sample CP-3 has polymodal shape with variety of pore throat sizes ranging from mostly micro to partly meso. Sample CP-4 has almost bimodal shape with variety of pore throat sizes ranging from micro to mostly around meso size. Figure 1 shows inherent heterogeneity in carbonates. For carbonate reservoirs "n" can greatly be affected by the pore structure [3]. Therefore it is recommended to evaluate "n" on representative samples from different facieses of the reservoir formation.

The pore distribution network in carbonate rocks ranges from micro to macro to polymodal, including the fracture network. This makes them very complex and heterogeneous. In a rock with bimodal pores of two sizes (large to medium and micro), the connate water may exist only in the micro pores while the large to medium pores are filled with hydrocarbon. In this case, the values of "n" are often near 2 at high water saturations and much less than 2 at low water saturations. Samples CP-1 and CP-2 show such a trend.

Wettability, micro-porosity and capillary effects are the main factors which influence the nonlinear behavior of resistivity index versus water saturation [16]. Water saturation is dominated by the largest volume of water in porous media, which are the pore bodies. Resistivity is dominated by the smallest restrictions in the ion path within the porous media, which are the pore throats [17]. The nonlinearity is attributed to hysteresis effects controlled by pore structure and wettability [6]. It is believed that at capillary and electrical equilibrium a uniform saturation distribution can be achieved with porous plate technique, but small scale heterogeneity can cause non-linearity even after this equilibrium is achieved [16].

In this study, nonlinearity was not much considerable which can be an indication of proper experimentation and spending enough time for stability at applied capillary pressures. However, all samples indicated that a "b" parameter should be entered to the Archie equation. They showed almost equal values of "b" (=1.8) in imbibition process. Their obtained average "n" value significantly changes from forced fit to free fit regression.

Conclusions

- Researchers reported in the literatures a great variation for saturation exponent and its dependency on operating conditions. Therefore, a predetermined value of "n" cannot be used for a reservoir simulation study.
- Because errors in the evaluation of saturation exponent can give rise to serious errors in the estimation of hydrocarbon saturations, it is concluded that determination of saturation exponent requires particular care, and that fluids characteristics and the desaturation method should be carefully

selected whenever resistivity index measurements are performed.

- The origin point with R_t equal to R_o, which some factors like wettability are not implied, should not be used in regression especially in the case of oil-wet samples. This insists the use of a "b" (can be called saturation distribution) factor in the Archie equation.
- Saturation exponent is influenced by many factors which ignoring one of them may cause unpredictable impact in no measurable way. The final and the most important conclusion of this article is to measure resistivity index and consequently saturation exponent at proper conditions of target reservoir, on representative formation samples using live reservoir fluids and in correct desaturation process.

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