A CASE STUDY OF SATURATION EXPONENT MEASUREMENT ON SOME CARBONATE CORES AT FULL RESERVOIR CONDITIONS

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ABSTRACT
Application of Archie equation in carbonate reservoirs is not easy due to high dependency of its parameters on carbonate characteristics. Carbonates are very heterogeneous in nature and hydrocarbon reserves in these mostly oil-wet and intermediate-wet reservoirs, are highly influenced by the input values of saturation exponent. To our knowledge, non-representative oils have been used in most saturation exponent measurements and live oils have not been used in many cases on carbonate cores at full reservoir conditions. Performing these experiments at laboratory conditions would not yield representative results and therefore these experiments should be performed at reservoir conditions.

The main objective of this study was to measure saturation exponent on carbonate core plugs at reservoir conditions, using live oil, by the porous plate technique. Resistivity index and capillary pressure were measured by drainage process on some plugs from the pay-zone and imbibition process on some plugs from near and within the transition zone of the studied reservoir. Linear regression fits by using Archie equation were poor. These linear regressions were improved by including the “b” factor in the Archie equation.
Keywords: Archie equation; saturation exponent; resistivity index; drainage; imbibition.

INTRODUCTION
The standard method of relating hydrocarbon saturation to resistivity in a clay free rock is based on the Archie’s 1942 methodology [1]. The Archie equation is made up of two parts; the “Resistivity Index” (RI) (Eq. 1) and the “Formation Resistivity Factor”:

$$RI = \frac{R_t}{R_o} = \frac{1}{S_W{}^n} \tag{1}$$

Great varieties of carbonates exist that are classified based on their lithology, texture and structure. Archie equation is not easy to be applied to these reservoirs because “a”, “m”, and “n” are functions of the changes in pore geometry, clay content, tortuosity of the pores, formation pressure, and wettability. The Archie equation is valid only when the rock is strongly water-wet and clay-free, which is not the case in these carbonate rocks [2]. Therefore as many researchers and petroleum engineers believe, the best alternative is to measure these parameters at reservoir conditions using representative core samples and reservoir fluids [2, 3, 4].

Performing saturation exponent and cementation factor experiments under experimental conditions which sometimes differ greatly from reservoir conditions will yield unrepresentative results. Anderson [5] stated that with the exception of highly water-wet rocks; the resistivity index-water saturation (RI-S_W) relationship is affected by wettability, and unless the reservoir is strongly water-wet, the value of “n” must be measured with preserved or restored samples at reservoir conditions. Longeron [3] obtained different values of “n” using reservoir oil and refined oil. This is attributed to the wettability changes of the cores in contact with crude oil.

The effect of saturation history (drainage and imbibition) has been also investigated by some researchers [6, 7]. They found that drainage/imbibition saturation exponents are not significantly different, except for strongly oil-wet cores. The effect of confining pressure on “n” was also studied by Langeron [3]. He concluded that confining pressure can increase or decrease ‘n’, depending on the rock type. Hence, reliable “n” values can only be obtained at representative reservoir pressure and temperature.

In the Archie equation the RI parameter at 100% water saturation is forced to 1. This has no basis since the derivation of “n” is a graphical and empirical technique. Many intercepts can be found which are not equal to 1 [8]. This indicates that an adjustable intercept, “b” factor, is missing in the equation [2, 9]. Some studies on oil-wet or intermediate-wet cores as well as the samples tested in this study showed the need of a factor that changes Equation 1 to Equation 2. The “b” factor can be called “saturation distribution factor” which depends on the pore structure, water distribution and wettability.

$$RI = \frac{b}{S_w{}^n} \tag{2}$$

THE EXPERIMENTAL SETUP AND PROCEDURE

A porous plate system capable of measuring full cycle capillary pressure curves was employed. Due to long duration of the tests, “m” and “n” were measured on four 1.5″ diameter core plugs of 2″ long from different zones of a carbonate reservoir in the South of Iran (Table 1). 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.

Longeron [3] and Maute [10] indicated that “n” values obtained from drainage resistivity index measurements should be used for primary evaluation of hydrocarbon, initially in place. In the transition zone and the flooded areas, the “n” values should be taken from imbibition measurements. In order to use the correct “n” values for petrophysical studies, the samples from reservoir pay-zone underwent a drainage process and the samples from near and within transition zone underwent an imbibition process.

Tests Procedure

The cleaned plug samples were vacuumed for 2 hours and then were saturated with prepared synthetic brine of 240,000 PPM. Hydrophobic and hydrophilic porous plates were saturated by n-Decane and brine respectively. n-Decane was used as the oil phase for pressurizing the samples to reservoir pore (4300 psig) and confining (6860 psig) pressures and temperature (196°F). When the system was established to desired conditions, n-Decane was removed by pre-heated live oil through a micro-valve at 4300 psig pressure. The samples were then allowed to reach stability under capillary pressure of -5 psig for 3 days for obtaining "R_o". Cementation factor of the samples was then calculated (Table 1).

Samples CP-1 and CP-2 underwent a drainage process. Due to long duration of the tests, capillary pressure was increased in 5 steps. The tests were continued for long enough to reach stability (Table 2) as Longeron [3] concluded that carbonate rocks required longer equilibration times than sandstones. The criteria used for equilibrium was ±0.02 cc production/day. Samples CP-3 and CP-4 underwent an imbibition process in which live oil was injected into the samples to reach irreducible water saturation (IWS). 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 in imbibition process was decreased in limited steps (Table 2). The average value of "n" was calculated from the slope of resistivity index curve versus 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 (Figures 2, 4, 6 and 7).

EXPERIMENTAL RESULTS AND DISCUSSION

In the Archie equation it is assumed that water saturation is distributed uniformly throughout the sample and all the brine contributes to the electrical current, and that the saturation exponent is constant. This is generally true in highly water-wet rocks where electrical continuity in brine is maintained down to low S_W values [8]. In this study, like in many other cases, measured "n" values were changing with different established water saturations during both drainage and imbibition processes (Table 2). Minimum IWS`s of 54.0%, 51.8% and 49.3% 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 or partly occlusion of the porous plates by high asphaltene content of the live oil. Some researchers believe that the saturation exponents measured at the onset of the imbibition resistivity index tests provide the most reliable "n" values as they are determined on restored samples prior to any hysteresis [8]. 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.

Sharma and coworkers [11, 12] stated that in their study oil-wet cores showed a large increase in "n" during both drainage and imbibition cycles. Samples CP-1 and CP-2 did not show a large increase or decrease of measured "n" values during drainage process; however "n" increased at IWS. The measured "n" values from imbibition process were increasing when water saturation decreased. The "n" value almost doubled for sample

CP-4. Anderson [5] indicated 2 reasons for the sharp increase of “n” values in carbonate rocks, (i) trapping of water in the oil and (ii) fingering of water.

Pore size distribution (PSD) of samples is presented in Figure 1. Varieties of pore throat sizes were present. 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 [12]. Samples CP-1 and CP-2 show such a trend. All samples indicated that a “b” parameter should be entered to the Archie equation. Almost equal values of “b” (1.8) were obtained in imbibition process.

CONCLUSION

There is a considerable variation in measured saturation exponents. Reported ‘n’ values depend on many factors, including the conditions at which the measurements were made, which ignoring one of them may change the results in no measurable way. Therefore the best way is to measure resistivity index at the correct conditions of the target reservoir under consideration, on representative formation rock samples, using live reservoir fluids, and the correct desaturation process. In carbonate reservoirs “n” can greatly be affected by the pore structure; hence, it is strongly recommended to evaluate “n” on representative samples from different facieses of the reservoir pay-zone. 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” (saturation distribution) factor in the Archie equation.

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Table 1) samples properties and water resistivity at test condition

Sample ID	Porosity (%)	Air Permeability (mD)	Archie`s Classification	Rw @ test condition (Ohm)	Cementation factor (m)
CP-1	23.09	14.586	II, A/B	0.023	1.90
CP-2	14.28	1.404	I/II, A/B		2.39
CP-3	21.99	1.788	II, A/B		2.03
CP-4	25.06	20.853	II, A/B, vugs		1.99

Table 2) saturation exponent measurement on selected core plugs

Sample ID	P_C, psig	Days for Stability	S_w	RI	n	Sample ID	P_C, psig	Days for Stability	S_w	RI	n
CP-1 (drainage process)	-5.0	3	1.0000	1.00	—	CP-3 (imbibition process)	-5.0	3	1.0000	1.00	—
	10.0	23	0.6842	2.13	2.00		110.0	68	0.5176	5.24	2.52
	30.0	13	0.6042	2.54	1.85		-5.0	8	0.5685	4.43	2.64
	70.0	8	0.5683	2.82	1.83		-30.0	18	0.6759	3.43	3.15
	110.0	24	0.5400	3.23	1.90		—	—	—	—	—
CP-2 (drainage process)	-5.0	3	1.0000	1.00	—	CP-4 (imbibition process)	-5.0	3	1.0000	1.00	—
	10.0	14	0.4193	6.31	2.12		110.0	59	0.4927	2.95	1.53
	30.0	19	0.2542	10.96	1.75		-5.0	7	0.5798	2.69	1.82
	70.0	24	0.1349	25.44	1.62		-20.0	13	0.6642	2.42	2.16
	110.0	11	0.1193	32.58	1.64		-90.0	7	0.7505	2.22	2.78

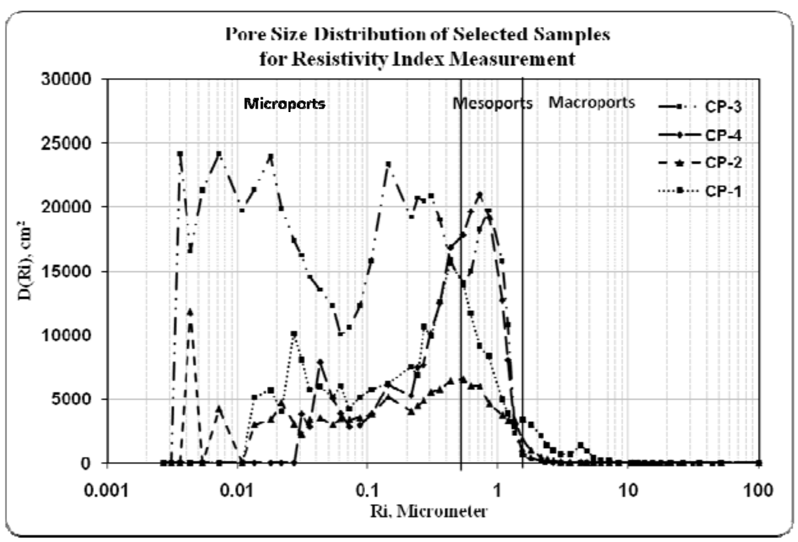

Figure 1) Pore Size Distribution of selected samples from mercury injection method.

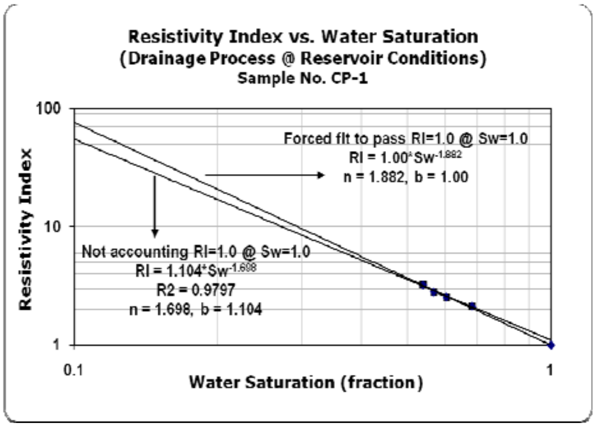

Figure 2) measured resistivity index values vs. water saturation of sample CP-1 from drainage process and two fitted regression curves.

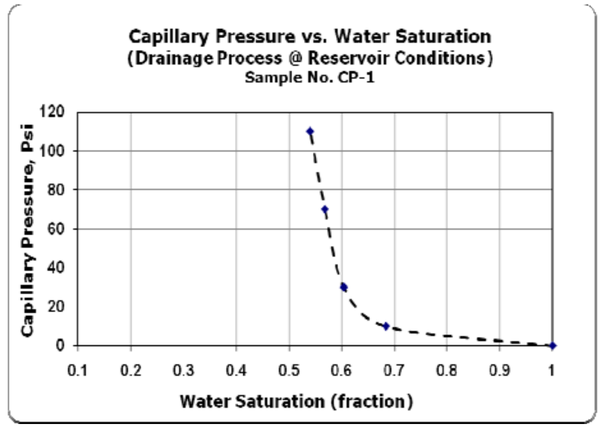

Figure 3) measured drainage capillary pressure vs. water saturation of sample CP-1 at reservoir conditions.

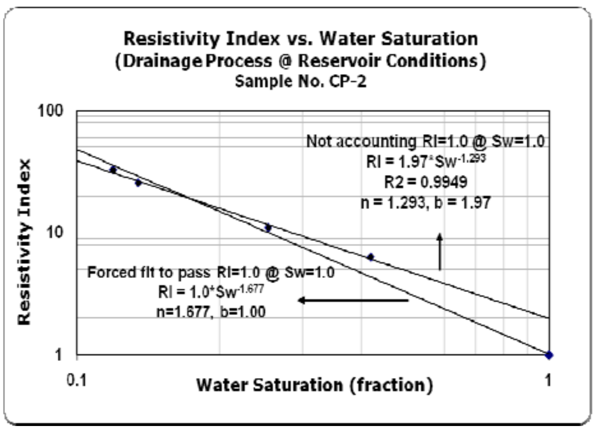

Figure 4) measured resistivity index values vs. water saturation of sample CP-2 from drainage process and two fitted regression curves.

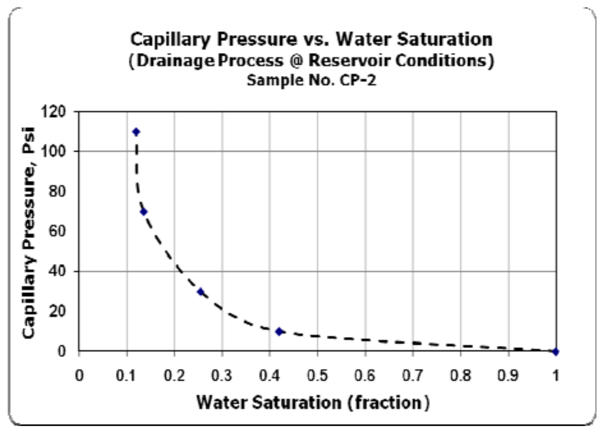

Figure 5) measured drainage capillary pressure vs. water saturation of sample CP-2 at reservoir conditions.

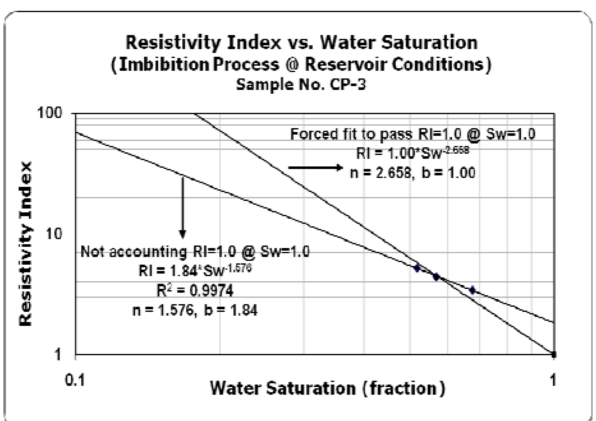

Figure 6) measured resistivity index values vs. water saturation of sample CP-3 from imbibition process and two fitted regression curves.

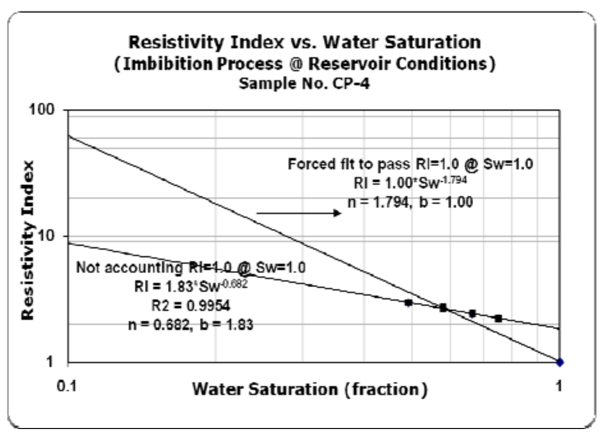

Figure 7) measured resistivity index values vs. water saturation of sample CP-4 from imbibition process and two fitted regression curves.