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I-B Shaly Sand Model: Application to Hydrocarbon Detection

G. IPEK*
*Member of Petroleum Society
Z. BASSIOUNI, B. KURNIAWAN, J.R. SMITH
Louisiana State University

Abstract

Hydrocarbon bearing shaly formations can be detected using cation exchange capacity (CEC) shaly sand models. Most CEC shaly sand models still depend on a laboratory measurement of the CEC value. In addition, these models use one value of formation resistivity factor which is a function of the rocks's cementation exponent. Using one formation resistivity factor in shaly sand reservoirs can result in overestimation of the water saturation, which in turn results in overlooking formations with hydrocarbon potential.

This paper introduces a new CEC shaly sand model, Ipek-Bassiouni (I-B), that improves the definition of the formation resistivity factor used in shaly sand formations. This model can also calculate the CEC value directly from the well log data.

The Ipek-Bassiouni (I-B) Shaly Sand Model considers that an electric current follows two types of paths in shaly sand. One path represents current flow in free water, and another path represents current flow in bound water. The differentiation between these two paths is accomplished by using two different formation resistivity factors in free water and bound water. The two formation resistivity factors are expressed using two cementation exponents for free water and for bound water.

The validity of the model was checked using the cation exchange capacity measured from core samples and drill cuttings. Calculated CEC values display a good agreement with the measured CEC values. The estimated water saturations from the model indicate better hydrocarbon detection in the zone of interest.

Introduction

Water saturation of hydrocarbon bearing shaly formations can be determined using available CEC shaly sand models. Current CEC models are based on cation exchange capacity and the ionic double layer concept. However, the use of these models is impractical because most of the time CEC data is not usually available to the log analyst, hence, a laboratory measurement of CEC is required. Different laboratory techniques to measure this parameter are found to yield different CEC values for the same core sample.

Previous researchers at Louisiana State University (LSU)[1-7] have developed a shaly sand interpretation technique, referred herein as the LSU model, based on log data such as resistivity, spontaneous potential, neutron and density logs. This model is based on the Waxman and Smits[8] concept of supplementing water conductivity with clay counterions conductivity. It also utilizes the dual water theory[9], which relates each conductivity term to a particular type of water, free and bound, each occupying a specific volume of the total pore space. The main assumption of the LSU model is that the counterion conductivity is represented by a hypothetical sodium chlorite solution. The LSU model is a practical approach that represents the conductivity behaviour of shaly sand. However, same as all previous models, the LSU model also assumes that the electric current follows the same path in both free and bound water areas. This leads to the use of the same formation resistivity factor to evaluate the shaly formations. This assumption can cause hydrocarbon bearing shaly formations to be overlooked due to overestimation of water saturation in the zone of interest.

The Ipek-Bassiouni (I-B) shaly sand model, which is also based on the LSU shaly sand model's concept, improves the assumption used in all previous models, where only one formation resistivity factor is applicable. This model is validated using the measured CEC of conventional core samples from Field B and drill cuttings from the Matagorda Island (MI) field. Both are located in the United States. The I-B model is also applied to detect hydrocarbon-bearing formations using log data from two fields; one in Indonesia and another in California, USA.

I-B Shaly Sand Model

The Ipek-Bassiouni model is based on Waxman and Smits[8] concept of supplementing the water conductivity with clay counterions conductivity and the dual water[9] theory relating the conductivity term to a particular type of water, free and bound, each occupying a specific volume of the total pore space. Like previous LSU models[1-7], it also assumes that counterion conductivity is represented by a hypothetical sodium chloride, NaCl, solution.

The proposed shaly sand model in this paper consists of two equations; namely, the conductivity and the spontaneous potential equations. Both equations utilize resistivity, spontaneous potential and density logs in their computation. The development of these equations is explained in the following two sections.

Conductivity Equation

First, a parallel conductance for free water and bound water is assumed as in Waxman and Smits'[8] shaly sand model. Water bearing conductance, C_o, can be written in terms of formation water conductivity, C_w, and clay conductivity, C_{cl}, as:

$$C_o = C_w / F_f + C_{cl} / F_{bw} \quad \text{..... (1)}$$

Assuming electric current follows the effective path in free water and the bound porosity path in bound water, then two formation resistivity factors should be applied to represent both formation resistivity factors for free water, F_f, and bound water, F_{bw}. Because the formation resistivity factor is a function of the porosity and cementation exponent, F_f and F_{bw} can be expressed as:

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$$F_f = 1/\phi_e^{mf} \quad \text{..... (2)}$$

$$F_{bw} = 1/\phi_{bw}^{mc} \quad \text{..... (3)}$$

where ϕ_e, ϕ_{bw}, *mf* and *mc* are effective porosity, bound water porosity, cementation exponent of free water and cementation exponent of bound water, respectively.

Furthermore, according to Hill, Shirley and Klein[10], effective and bound porosity, ϕ_e and ϕ_{bw}, can be defined as in Equations (4) and (5), respectively, where v_{fdl} is the fractional volume of the double layer and ϕ_t is the total porosity.

$$\phi_e = \phi_t\left(1 - v_{fdl}\right) \quad \text{..... (4)}$$

$$\phi_{bw} = \phi_t v_{fdl} \quad \text{..... (5)}$$

Substituting Equations (4) and (5) into Equation (1) results in:

$$C_o = C_w\left(1 - v_{fdl}\right)^{mf} \phi_t^{mf} + C_{cl}\left(v_{fdl}\phi_t\right)^{mc} \quad \text{..... (6)}$$

Assuming that clay conductivity can be represented by an equivalent sodium chloride solution[1-7], Equation (6) becomes:

$$C_o = C_w\left(1 - v_{fdl}\right)^{mf} \phi_t^{mf} + C_{eq} n_{eq} v_{fdl}^{mc} \phi_t^{mc} \quad \text{..... (7)}$$

The parameters, such as molar counterion conductivity of an equivalent NaCl solution, C_{eq}, molar counterion concentration of an equivalent NaCl solution, n_{eq}, and fractional volume of double layer, v_{fdl}, are expressed empirically as illustrated in Appendix A.

Hydrocarbon bearing formation conductivity, C_t, is defined as:

$$C_t = \left[C_w\left(1 - v_{fdl}\right)^{mf} \phi_t^{mf} + C_{eq} n_{eq} v_{fdl}^{mc} \phi_t^{mc}\right] S_w^n \quad \text{..... (8)}$$

Estimation of *mc* and *mf*

In clean sand and perfect shale formations, the I-B shaly sand conductivity equation becomes, respectively:

$$C_{cs} = C_{wf} \phi_t^{mf} \quad \text{..... (9)}$$

$$C_{sh} = C_{bw} \phi_t^{mc} \quad \text{..... (10)}$$

A log-log plot of C_{cs} versus ϕ_t and C_{sh} versus ϕ_t yields a slope equivalent to the *mf* and *mc*, respectively.

Hence, electrical and porosity values from a water-filled clean sand and a shale interval adjacent to the shaly formation are used to construct the C_{cs} versus ϕ_t and C_{sh} versus ϕ_t plots so that *mf* and *mc* can be graphically determined. The total porosity values are taken as the average of density and neutron log readings. It is expected that *mc* > *mf* since the tortousity of the shale formation is usually higher than clean sand.

Spontaneous Potential Equation

The spontaneous potential, *SP*, is composed of electrokinetic and electrochemical potential. The electrokinetic, streaming potential is small and can be neglected. The electrochemical potential, however, consists of two components; a membrane potential across shale and a membrane potential across the shaly sand. When the formation is shaly, the membrane across the sand increases due to the presence of a clay double layer. This effect is proportional to the amount of clay.

The presence of electrochemical potentials of shales, Em_{sh}, and adjacent shaly sands, Em_{ss}, is given by the *SP* deflection recorded in front of a permeable formation with respect to the shale baseline. This results in:

$$SP = Em_{sh} - Em_{ss} \quad \text{.....(11)}$$

or in terms of cation transportation number, T_{na}, it is defined in Equation (12)[6] where *F* is the Faraday constant, *R* is the universal gas constant and T_a is the absolute temperature.

$$SP = \frac{-2RT_a}{F} \int_{m2}^{m1} \left(T_{na}^{sh} - T_{na}^{ss}\right) d\ln\left(m\gamma\pm\right) \quad \text{..... (12)}$$

Molal concentration, *m*, and mean activity coefficient, γ, are explained in Appendix A.

Cation transport number, T_{na}, is defined as in Equation (13), where t_{na}^+ is the sodium transport number, also explained in Appendix A.

$$T_{na} = \frac{C_{eq} n_{eq} v_{fdl}^{m_e} + t_{na}^+\left(1 - v_{fdl}\right)^{m_e} C_w}{C_{eq} n_{eq} v_{fdl}^{m_e} + \left(1 - v_{fdl}\right)^{m_e} C_w} \quad \text{..... (13)}$$

Assuming electric current follows two different paths, one for free water and another for bound water, Equation (13) can be rearranged. Henceforth, T_{na} can be expressed as in Equation (14).

$$T_{na} = \frac{C_{eq} n_{eq} v_{fdl}^{mc} + t_{na}^+\left(1 - v_{fdl}\right)^{mf} C_w}{C_{eq} n_{eq} v_{fdl}^{mc} + \left(1 - v_{fdl}\right)^{mf} C_w} \quad \text{..... (14)}$$

Both T_{na}^{ss} and T_{na}^{sh} in Equation (12) can be expressed using a general expression of cation exchange number of membrane, T_{na}. However, it is not practical to apply Equation (13), or in this model, Equation (14) to shale because C_w of shale cannot be determined from wireline data. To overcome this difficulty, it is commonly assumed that shale behaves as a perfect membrane and v_{fdl} and T_{na}^{sh} are assumed to be equal to 1. In reality, free water exists in pore spaces and T_{na}^{sh} is less than 1. Therefore, a new term, called membrane efficiency, m_{eff}[1-7], is used in place of T_{na}^{sh}.

Using the membrane efficiency term, and combined with Equations (12) and (14), the *SP* equation in the I-B shaly sand model is expressed as:

$$SP = \frac{-2RT_a}{F}\left[\int_{m2}^{m1} m_{eff}\, d\ln\left(m\gamma\mp\right) - \int_{m2}^{m1} \frac{C_{eq} n_{eq} v_{fdl}^{mc} + t_{na}^+\left(1 - v_{fdl}\right)^{mf} C_w}{C_{eq} n_{eq} v_{fdl}^{mc} + \left(1 - v_{fdl}\right)^{mf} C_w} d\ln\left(m\gamma\mp\right)\right] \quad \text{(15)}$$

Validation

The Ipek-Bassiouni shaly sand model is validated by comparing the log-derived CEC from the model to the measured CEC from conventional cores and drill cuttings.

Two measured CEC data sets, from the Matagorda Island field and Field B in the United States, were used. A total of 20 drill cuttings taken over 30 ft intervals from Matagorda Island were measured for their CEC values, while 28 conventional core samples representing four different formations from Field B were also measured for their CEC values.

The CEC values were also calculated using the I-B model from available log data of the respective interval where rock samples were acquired for laboratory measurement. Both equations in the I-B shaly sand model, conductivity and spontaneous potential

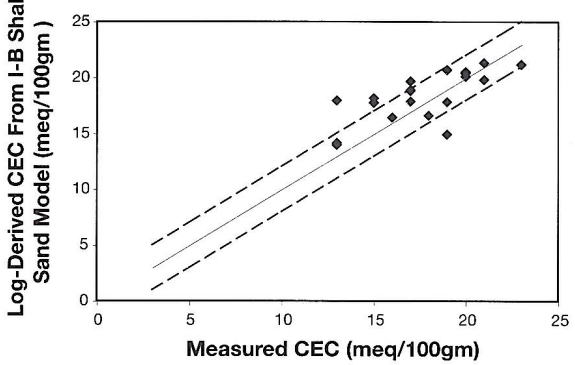


FIGURE 1: The measured CEC vs. log-derived CEC for MI field.

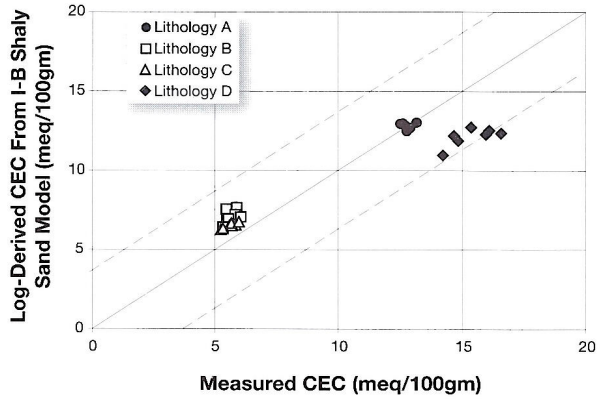


FIGURE 2: The measured CEC vs. log-derived CEC for Field B.

equations, were used simultaneously to solve the log-derived CEC values.

To validate the result, a statistical approach was applied. The slope of the regression line between the log-derived CEC and the measured CEC, β, with zero intercept, is calculated. The slope of regression line is tested for a null hypothesis of $\beta = 1$ using the t-test statistics with significance level, α, of 0.01 as shown in Equations (17) and (18). The s_p is the estimated standard deviation.

$$H_o : \beta = 1 \quad \textit{Null Hypothesis} \qquad \text{.....(16)}$$

$$\left| t = \frac{\beta - 1}{s_p} \right| < t_{(\alpha/2, n-2)} \quad \textit{fail to reject null hypothesis} \qquad \text{.....(17)}$$

$$\left| t = \frac{\beta - 1}{s_p} \right| \geq t_{(\alpha/2, n-2)} \quad \textit{reject null hypothesis} \qquad \text{.....(18)}$$

Figures 1 and 2 illustrate the measured CEC versus log-derived CEC from Matagorda Island and Field B, respectively. The 45° line represents the zero difference between the calculated CEC and measured CEC: the slope of 1. The dashed line represents that all log-derived CEC within these lines are in agreement with the measured ones.

From Figure 1, the estimated t statistics of testing $\beta = 1$ is 1.8027, which is less than 2.8784, $t_{(0.005,18)}$. Henceforth, we fail to reject the null hypothesis H_o: $\beta = 1$. Estimated R^2 of this test is 0.9879 with an adjusted R^2 of 0.9873.

Figure 2 illustrates the log-derived CEC vs. measured CEC for Field B. Four different intervals are illustrated as A, B, C and D. Interval A is very black, splintery, easily fractured shale. Interval B is light gray, fine grained, with interlaminated to thin beds of dark shale local flame structure. Interval C is medium gray, sparse, thin fine-grained sandstone and siltstone laminae, sparse siltstone beds shale. Interval D is dark gray, fissible in part, calcareous, and less pyrite Wapanucka formation shale. At least six samples were taken in each interval, which had the same type of lithology for the purpose of laboratory experimental accuracy.

From Figure 2, the slope of the regression line between log-derived CEC and measured CEC with zero intercept is 0.91622. The estimated R^2 of this test is 0.9720 with an adjusted R^2 of 0.9709.

In Figures 1 and 2, the dashed lines represent the ± pooled standard deviation from the 45° line. In the comparison of pooled standard deviations from Figures 1 and 2, the pooled standard deviation for Field B is greater than the one for the MI field which is due to clustered distribution of the measured CEC data within the lithology, but widely spread distribution amongst lithologies for Field B. On the contrary, it is relatively evenly distributed within the range of all measured CECs for the MI field.

As a conclusion, the log-derived CEC values are validated reasonably well with the measured CEC values.

Hydrocarbon Detection

Detection and evaluation of hydrocarbon zones is the main objective in petroleum exploration. The potential of a hydrocarbon zone is usually estimated by calculating porosity, ϕ, and water saturation, S_w. In this section, the I-B shaly sand model is applied to one well in Indonesia and one well in California.

Well A

Figure 3 illustrates gamma ray, resistivity and porosity logs for an interval of Well A.

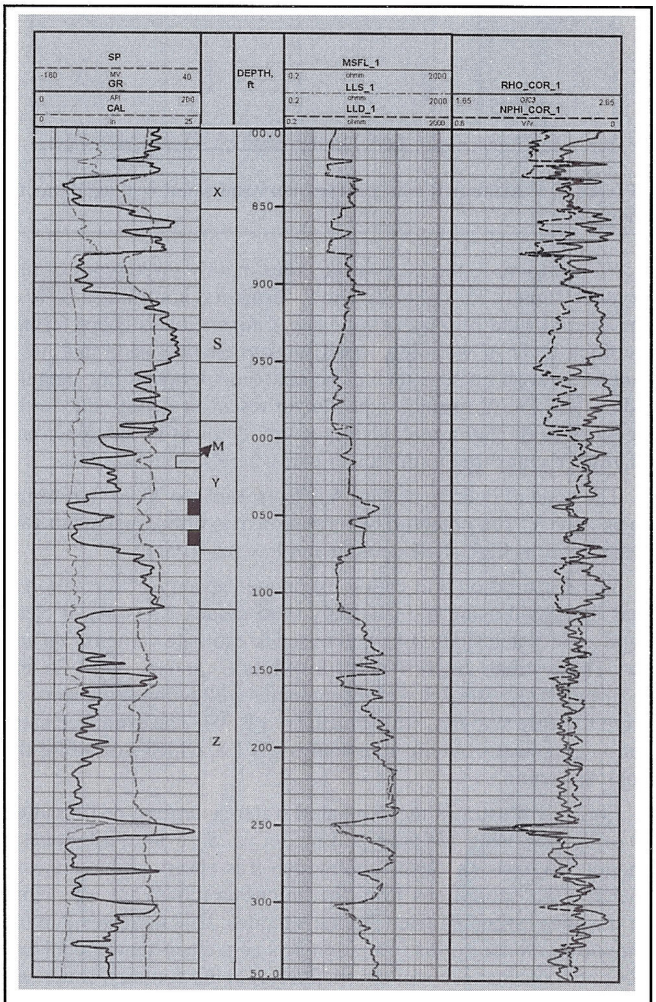


FIGURE 3: The gamma-ray, resistivity, density and neutron log data of Well A[12].

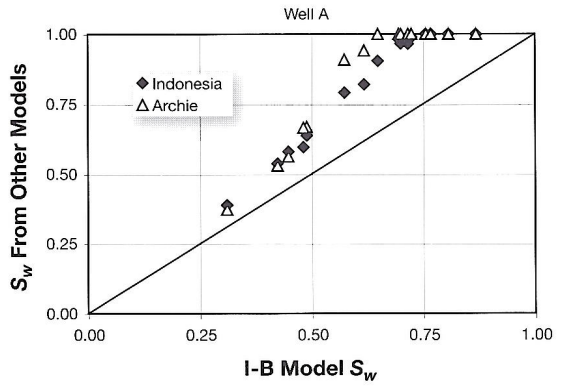


FIGURE 4: Estimated water saturation (S_w) using I-B model compared to other models.

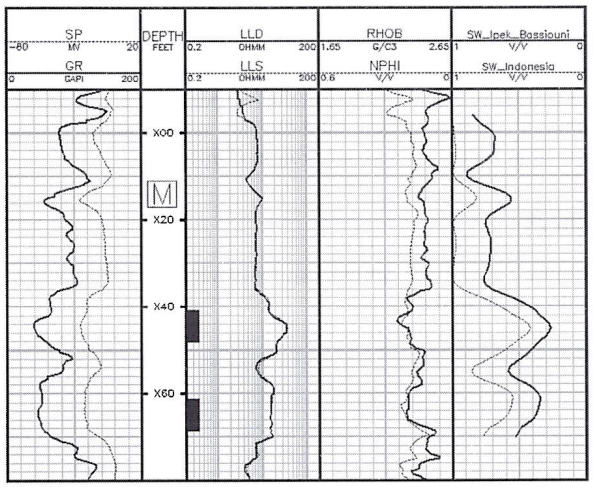


FIGURE 5: Estimated water saturation results and well log data of Well A.

From Figure 3, the interval includes mainly three types of reservoirs; namely X, Y and Z. The Z formation contributes 80% of the overall field oil production. The Z formation is characterized by thick layer of well-developed stacked channel sand that has a better reservoir quality, such as porosity and permeability, than the other two. The Y formation has lower reservoir quality due to the occurrence of clay minerals. Resistivity is lower in the upper part of zone Y compared to the lower part where shaliness is less.

The zone of interest in Well A is from X997 to X070 ft, referred to as zone Y. The potential of formation Y is often underestimated because of its high shale content and low resistivity.

Water saturation and cation exchange capacity of formation Y was estimated using the I-B shaly sand model. The data of clean sand zone X and shale zone S are used to estimate values of *mf* and *mc*. These values are 1.57 and 1.89 while C_w and m_{eff} are 1.28 and 1, respectively. The value of *mf* compares well with the one derived from the core analysis, which measured 1.603. The estimated saturation exponent from the core analysis is 1.8, which is used for the analysis herein.

Figure 4 illustrates the estimated water saturation of formation Y of Well A using the proposed model vs. S_w from the Indonesia model and Archie's clean sand model. It is observed that the estimated water saturations from the Indonesia model are very close to the ones estimated from Archie's model. This indicates that the Indonesia model in this formation acts as a clean sand model and does not take into account the shaliness. On the contrary, water saturation calculated using the I-B model are approximately 25 – 30% lower than the ones from Archie's model, which shows that the I-B model takes into account shaliness.

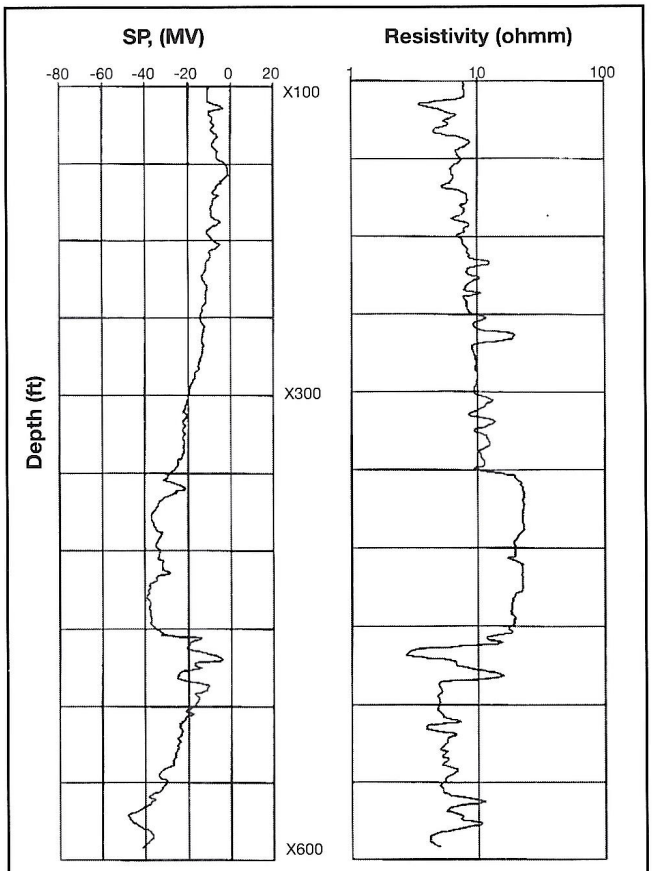


FIGURE 6: The spontaneous potential and resistivity log data of Well B[12].

Figure 5 shows the water saturation from the proposed model in this paper versus depth. From Figure 5, estimated water saturation is approximately 0.57 in zone M between X010 and X020, which is significantly lower than the ones from the Indonesia model. This well is perforated between X041-X048 and X061-X068 in the cleanest parts where all models give relatively low S_w values. The total water cut from these two perforated intervals is reported as 5%, which confirms relatively low water saturation.

The upper part of the sand was not perforated because of high S_w values calculated from the Indonesia model. The I-B shaly sand model yields an average 57% S_w in zone M that is consistent with the irreducible water saturation of low permeability sands. The low permeability is the result of a decrease in the grain size as indicated by gamma ray. This small grain size is common in the existing 'estuarine' depositional environment. The proposed model's results with the depositional environment suggest that zone M at the depth of X015 should have been tested and should be tested in the future.

Well B

Well B was drilled onshore in California. The interval of study is between X100 and X450. The *SP*, resistivity and gamma ray porosity logs are presented in Figures 6 and 7, respectively.

In this well, the deep induction log shows an increase in the interval between X350 and X462. The high resistivity readings were associated with low salinity water. This interval was tested and produced with 100% water. The I-B shaly sand model was used to estimate the water saturation in this interval with $mf = 1.27$, $mc = 1.5$, while C_w and m_{eff} are 0.4 and 1, respectively. The proposed model predicted $S_w = 100\%$ in this zone. This value shows a good agreement with the production test.

The proposed model also predicted that the interval between X105 and X350 ft would be a hydrocarbon-bearing formation (see Figure 8). This interval was also tested and produced 90% oil and

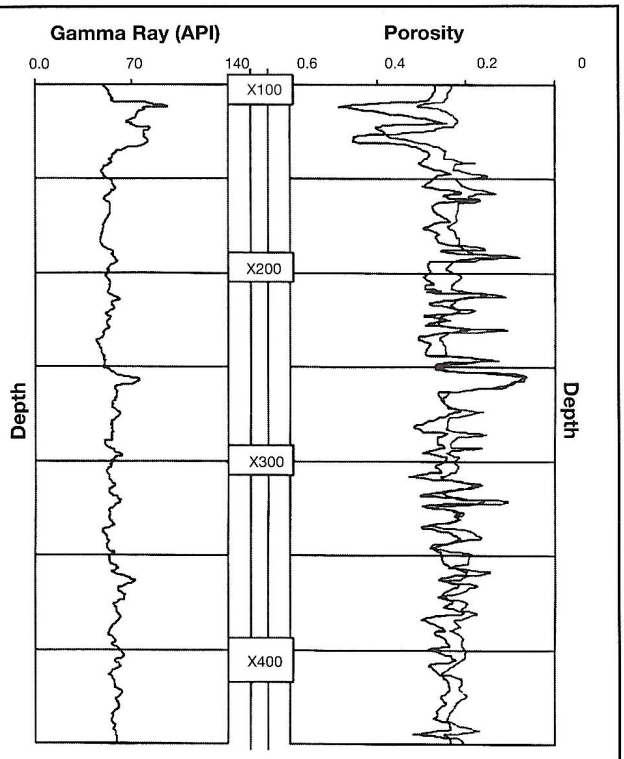


FIGURE 7: The gamma ray and porosity log data of Well B[12].

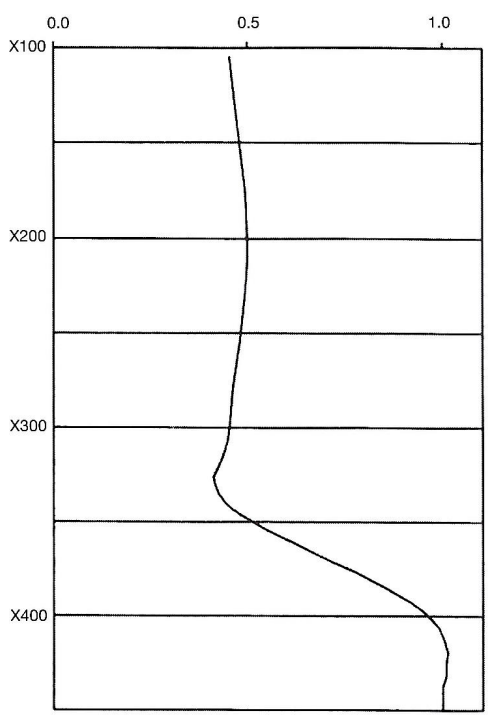


FIGURE 8: The estimated water saturation using I-B shaly sand model for Well B.

10% water. The estimated water saturations from the proposed model are also in agreement with the production test.

Conclusion

A new shaly sand model has been developed. This model makes use of conductivity and spontaneous potential equations. This model is based on both cation exchange capacity and the dual water concept. The bound water is represented by an equivalent sodium chlorite solution.

The main assumption of the proposed model is the incorporation of two formation factors: one for free water and another for bound water. Accordingly, the electric current follows the effective porosity path in the free water and follows the bound water porosity path in the bound water part. All previous models incorporate only one formation factor.

The new model is validated by comparing the log-derived CEC from this model to those measured on cores and drilling cuttings. Essentially, the log-derived CEC values are validated reasonably well with the measured CEC values.

Key applications of this model are:

1. The estimation of cation exchange capacity of shaly sands from log data.
2. Estimation of a more representative fluid saturation of shaly sands reservoirs.

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NOMENCLATURE

CEC = cation exchange capacity, meq/100gm
C_o = water-bearing formation conductivity, mho/m
C_t = hydrocarbon bearing formation conductivity, mho/m
C_w = formation water conductivity, mho/m
F_f = formation resistivity factor for free water
F_{bw} = formation resistivity factor for bound water
C_{cl} = clay conductivity, mho/m
C_{sh} = perfect shale formation conductivity, mho/m
C_{cs} = clean sand formation conductivity, mho/m
C_{wf} = formation water conductivity in a clean sand formation, mho/m
C_{bw} = bound water conductivity in a perfect shale, mho/m
ϕ_e = effective porosity, fraction
ϕ_{bw} = bound water porosity, fraction
ϕ_t = total porosity, fraction
mf = cementation exponent of free water
mc = cementation exponent of bound water
v_{fdl} = fractional volume of double layer
C_{mf} = conductivity of mud filtrate, mho/m
SP = spontaneous Potential deflection, mV
Em_{ss} = electrochemical potential of shales, mV
Em_{sh} = electrochemical potential of adjacent shaly sands, mV
R = universal gas constant, cal/(g*mole*°K)
F = Faraday constant, g*mole/cal
T_a = temperature, K
T = temperature, °C
T_{na}^{sh} = cation exchange number in shale
T_{na}^{ss} = cation exchange number in shaly sand
m_1 = molal concentration of formation water, mole/Kg
m_2 = molal concentration of mud filtrate, mole/Kg
$\gamma\pm$ = mean activity coefficient, Kg/mole
m = molal concentration, mol/kg
T_{na} = cation Transport number
t_{na}^{+} = sodium transport number
C_{eq} = molar counterion conductivity of an equivalent NaCl solution, (mho/m)/(mole/m)
n_{eq} = molar counterion concentration of an equivalent NaCl solution, mole/l
m_e = cementation exponent [Equation (13): represented by the same value for both shale and shaly sand in the previous models]
m_{eff} = membrane efficiency, fraction

t = t-test

α = significance level

s_p = estimated standard deviation

Q_v = volumetric cation exchange capacity, meq/cc

S_w = water saturation, fraction

n_1 = molarity of water

n_2 = molarity of mud filtrate

t_w = water transport number

T_{na}^h = Hittorf transport number

$\gamma_{\pm}^{298}$ = activity coefficient at 25°C

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Appendix A

Calculation of Fractional Volume of Double Layer[5, 7], v_{fdl}

Fractional volume of double layer, v_{fdl}, is related to the distance from the clay surface up to the point where the number of positive ions are equal to the negative ions, and it is calculated using Equation (A-1).

$$v_{fdl} = \left[0.28 - 0.0344 \ln\left(T/25\right)\right] 1/\left(6.18 B_o\right) n_1^{-1/2} Q_v \quad \text{(A-1)}$$

where;

$$n_1 = \exp\left[68.1 - 13.5791 \ln\left(T_a\right) + 0.02289 T_a + 1.1854 \ln C_w + 4.67 \times 10^{-3} \times C_w\right] \quad \text{(A-2)}$$

$$B_o = 0.3248 + 0.00015108 T + 8.935\left(10^{-7}\right) T^2 \quad \text{(A-3)}$$

In the case of hydrocarbon-bearing zones, the 'hydrocarbon effect' must be considered. This effect can be incorporated by substituting volumetric cation exchange capacity, Q_v, with Q_v'[1-7]:

$$Q_v' = \frac{Q_v}{S_w} \quad \text{(A-4)}$$

Calculation of Equivalent Molar Counterion Conductance[5], C_{eq}

The equivalent molar conductance can be calculated from Equation (A-5):

$$C_{eq} = \exp\left[-58.84 - 0.1026 n_{eq} - 0.0787 \ln\left(n_{eq}\right) - 0.0216 T_a + 11.85 \ln\left(T_a\right)\right] \quad \text{(A-5)}$$

Calculation of Equivalent Molar Counterion Concentration[12], n_{eq}

The equivalent molar counterion concentration can be calculated as follows:

$$n_{eq} = Q_v / v_{fdl} \times T_a / 298 \quad \text{(A-6)}$$

Calculation of Molal Concentration[12], m

Molal concentration of formation water, m_1, is calculated from Equation (A-7).

$$m_1 = \exp\left(1.5054 + 1.0142 \ln C_w + 0.2721 \ln T_a\right) \quad \text{(A-7)}$$

Molal concentration of mud filtrate, m_2, is calculated from Equation (A-8).

$$m_2 = \exp\left(1.5054 + 1.0142 \ln C_{mf} + 0.2721 \ln T_a\right) \quad \text{(A-8)}$$

Calculation of Sodium Transport Number[6], t_{na}^+

The sodium transport number is estimated from Equation (A-9).

$$t_{na}^+ = t_{na}^h + t_w \quad \text{(A-9)}$$

where,

$$t_{na}^h = \exp\left[-2.50893 - 0.018038 \ln\left(m\right) + 0.2647 \ln\left(T_a\right) - 1.4176 \times 10^{-5} T_a m\right] \quad \text{(A-10)}$$

for m < 1

$$t_w = 0.053m - 0.043 + \left[0.19661\ln(m) + 0.1244\right]Q_v \quad \text{(A-11)}$$

for m > 1

$$t_w = 0.036m^{1.1} - 0.04377 + 0.04Q_v \quad \text{(A-12)}$$

Calculation of Mean Activity Coefficient[7, 12], γ±

Mean activity coefficient, γ±, can be determined from the following equations:

$$\log(\gamma\pm) = \log\left(\gamma_{\pm}^{298}\right) + 0.5YL_{298} - 0.5ZJ_{298} \quad \text{(A-13)}$$

where,

$$\log\left(\gamma_{\pm}^{298}\right) = \frac{-0.5115n^{1/2}}{1+1.3065n^{1/2}} - 1.75\log(a_A) - \log(1-0.27m) \quad \text{(A-14)}$$

For mean activity coefficient of water and mud filtered, n replaces n_1 and n_2, respectively, where

$$n_1 = \exp\left[68.1 - 13.5791\ln T_a + 0.02289T_a + 1.1854\ln(C_w) + 0.00467C_w\right] \quad \text{(A-15)}$$

$$n_2 = \exp\left[68.1 - 13.5791\ln T_a + 0.02289T_a + 1.1854\ln(C_{mf}) + 0.00467C_{mf}\right] \quad \text{(A-16)}$$

$$a_A = 0.99948 - 0.030959m - 0.0015075m^2 \quad \text{(A-17)}$$

$$Y = \frac{298 - T_a}{8.3147(298)2.3026(T_a)} \quad \text{(A-18)}$$

$$Z = 298.15Y + \frac{1}{8.3147}\log(T_a/298) \quad \text{(A-19)}$$

$$L_{298} = \frac{2{,}878.6m^{1/2}}{1+m^{1/2}} - 3{,}182.8m + 986.5m^{3/2} \quad \text{(A-20)}$$

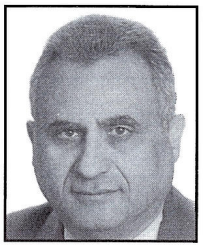
$$J_{298} = \frac{43.5m^{1/2}}{1+m^{1/2}} + 72m - 20.36m^{3/2} \quad \text{(A-21)}$$

Provenance—Original Petroleum Society manuscript, **I-B Shaly Sand Model: Application to Hydrocarbon Detection** (2005-160), first presented at the 6th Canadian International Petroleum Conference the 56th Annual Technical Meeting of the Petroleum Society), June 7-9, 2005, in Calgary, Alberta. Abstract submitted for review December 13, 2004; editorial comments sent to the author(s) August 3, 2006; revised manuscript received August 22, 2006; paper approved for pre-press August 28, 2006; final approval June 18, 2007.

Authors' Biographies



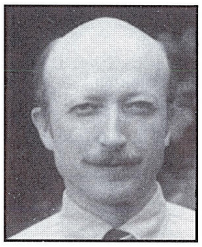
Gamze Ipek is working as a Research Scientist in the Heavy Oil and Oil Sands Business Unit at Alberta Research Council (ARC) in Calgary, AB. She received her B.Sc. degree from Istanbul Technical University, and her M.Sc. and Ph.D. degrees from Louisiana State University, all in petroleum engineering. She also has a minor degree in Applied Statistics from Louisiana State University. Her research interests include reservoir simulation of thermal oil recovery processes, particularly steam assisted gravity drainage and formation evaluation. She is a member of the Petroleum Society of CIM and SPE.



Zaki Bassiouni is a Professor of Petroleum Engineering and the Dean of the College of Engineering at Louisiana State University. Dr. Bassiouni received a B.S. in petroleum engineering from Cairo University, a diploma in geophysics from the Ecole Nationale Superieure de Petrole et des Moteurs of Paris, France, and M.S. (DEA) and Ph.D. (Docteur Es Sciences) degrees from the University of Lille, France. He is the author of the Society of Petroleum Engineers Textbook Series Vol. 4, "Theory, Measurement And Interpretation of Well Logs." Dr. Bassiouni is a member of the Society of Petroleum Engineers (SPE) and the Society of Professional Well Log Analysts (SPWLA). He served on the Education and Accreditation Commission (EAC) of the Accreditation Board of Engineering and Technology (ABET) from 1999 to 2004. Dr. Bassiouni is the recipient of the SPE Distinguished Achievement Award for Petroleum Engineering Faculty for 1995. He was a SPE Distinguished Lecturer for the 2004 – 2005 season.



Bobby Kurniawan works for Chevron Energy Technology Company in Houston, TX. Bobby received a B.Sc. in geology from Bandung Institute of Technology, Indonesia, and he holds M.S. and Ph.D. degrees in petroleum engineering from the Louisiana State University. His research interest is shaly sand characterization and reservoir properties modelling.



John Rogers Smith is an Assistant Professor in the Craft and Hawkins Department of Petroleum Engineering at Louisiana State University (LSU). He worked at Amoco Production Company for 23 years in drilling, production, facilities and research. His interests include deep drilling, well control, well design and well completions. He is a member of SPE, AADE and ASME; is a professional engineer; and, holds a B.S. degree in electrical engineering from the University of Texas, and M.S. and Ph.D. degrees in petroleum engineering from LSU. Dr. Smith was a SPE Distinguished Lecturer for 1999 – 2000, speaking on "Why Deep Drilling is Slow and Expensive, Even in Weak Rocks."

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