

SPECIAL CORE ANALYSIS CONSIDERATIONS IN THE DETERMINATION OF ELECTRICAL PROPERTIES OF SHALY ROCKS AT RESERVOIR CONDITIONS

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Abstract This paper presents some special core analysis considerations in the determination of the electrical properties and, therefrom, the volumetric parameters such as porosity and saturation of reservoir rocks. The following factors influencing the measurements of the electrical properties of reservoir rocks in the laboratory are considered, *i.e.*, confining pressure, temperature and clay minerals. Some details of a multi-sample high pressure and high temperature experimental system and a novel experimental procedure for making synthetic shaly rock samples with various clay type, content and distribution are also reported.

Systematic special core analysis experiments have been conducted on over 40 synthetic, outcrop and reservoir rock samples to investigate the effects of pressure and temperature on the electrical properties of clean and shaly rocks. An improved Waxman-Smits shaly sand conductivity model has been proposed which accounts for the effect of temperature and clay distribution on clay excess conductivity measurements. A quantitative parametric study based on the experimental data base and the improved Waxman-Smits shaly sand conductivity model is presented to demonstrate the significant influences of pressure, temperature and clay excess conductivity upon the determination of the electrical and volumetric properties of reservoir rocks.

INTRODUCTION

Special core analysis experiments are frequently performed in the laboratory to determine the porosity and saturation of reservoir rock samples and to provide a base line calibration for wireline log interpretations. So far, however, the influence of reservoir temperature and pressure on the electri-

cal properties of reservoir rocks, especially shaly rocks, has not been clearly established. The effect of clay excess conductivity at reservoir conditions, which appears to depend not only on clay type and volume but also clay distribution, temperature and perhaps pressure, remains a subject of ongoing investigation.

Clean formations

Although the era of formation evaluation using wireline logging techniques began from the first documented measurement of formation electrical resistivity by the Schlumberger brothers in September 1927, the quantitative interpretation of well-log results became possible only after the early 1940s. Archie (1942) defined two terms to describe the electrical resistivity of rocks, namely, formation factor ($F = R_o/R_w$) for formations completely saturated by brine, and formation resistivity index ($I = R_t/R_o$) for hydrocarbon bearing formations, where R_o and R_t are the resistivities of formations fully and partially saturated by brine, respectively, and R_w is the resistivity of the brine. Based on experimental data obtained from sandstone cores, the following two empirical relations were found by Archie:

$$F = \frac{1}{\phi^m} \quad (1)$$

and

$$I = \frac{1}{S_w^n} \quad (2)$$

where ϕ and S_w are the fractional porosity and water saturation, respectively, m is the Archie cementation factor defined as the negative slope of the $\log F$ vs. $\log \phi$ plot, and n , later defined as saturation exponent, can be determined experimentally taking the negative slope of a plot of $\log I$ vs. $\log S_w$. Combining the above two double-logarithmic trends gives the following well-known saturation equation for uninvaded, virgin formations:

$$S_w^n = \frac{R_w}{\phi^m R_t} \quad (3)$$

For the water saturation in the flushed zone, S_{xo} , a similar expression exists:

$$S_{xo}^n = \frac{R_{mf}}{\phi^m R_{xo}} \quad (4)$$

where R_{mf} is the mud filtrate resistivity and R_{xo} is the flushed zone resistivity. The water saturation S_w calculated from equation (3) is used in the determination of the total hydrocarbon in place for a reservoir with given size and porosity. The difference between S_{xo} of the flushed zone and S_w of the virgin zone defines the movable oil saturation (S_{mo}) for a given reservoir interval. Since most reservoirs are petrophysically heterogeneous in the vertical and lateral planes, averaging of saturation must initially be constrained within given rock types before including difference between rock types.

The resistivities of both the virgin and flushed zones, *i.e.*, R_t and R_{xo} , can be directly measured at *in situ* conditions, *e.g.*, from the deep induction log and a microfocused log, respectively. The porosity can be obtained from sonic, neutron and density logs, or a combination of porosity and lithology measurements. The R_w value can be calculated and verified from several sources including SP curve, calculation from nearby water-bearing zones, and/or water sample measurement (Schlumberger, 1989). The R_{mf} can be measured directly from the brine filtered from drilling mud and corrected to formation temperature. Finally, to ensure reliable and accurate determination of *in situ* water and hydrocarbon saturations from log interpretations, the proper value of cementation factor m , or the proper $\phi - F$ relationship, must be used. This relationship can be established in the laboratory on core plugs obtained from the regions of interest. The formation factor can also be measured *in situ* from adjacent water zones assuming the same R_w and the same rock.

The saturation exponent (n) varies with rock type and with the distribution of the brine and the non-conducting fluids within the pore spaces. Typically it has a value of 2 ± 0.5 for many water-wet reservoirs encountered. For oil-wet rocks, however, the value of n can be much greater than 2. During the parametric study later in this paper, the value of n is assumed to be 2 for all the rocks concerned.

Shaly formations

Since clay minerals in reservoir rocks can provide a second conductive path for cations in the brine, the Archie equations (3 and 4) cannot be applied to calculate water or oil saturation from resistivity logging data. If the effects of this excess conductivity associated with clays are ignored during the calculation of porosity and hydrocarbon saturation from electric logs in

shaly sands, the volume of hydrocarbon present may be underestimated.

There are numerous shaly sand interpretation models reported in the literature (Worthington, 1985). All these models comprise a clean term, described by the Archie water saturation equation (3), plus a shale term. The shale term may be fairly simple or quite complex; the shale term may be relatively independent of, or it may interact with, the clean sand term (Schlumberger, 1989). Based on the Waxman and Smits (1968) model, which has been widely accepted in the oil industry, Jing and Archer (1991) proposed a more advanced shaly sand conductivity model as follows:

$$\frac{1}{R_o} = \frac{1}{F'}(\omega B \cdot Q_{ve} + \frac{1}{R_w}) \quad (5)$$

where ω is the temperature coefficient for clay excess conductivity, B is the equivalent clay counterion conductivity and Q_{ve} is defined as the effective clay concentration of shaly sands which may be determined experimentally from the "multiple-salinity" or the "membrane-potential" measurements, or can be calculated from the Q_v based on *CEC* measurements (Jing, 1990). F' was defined as the pressure and temperature dependent formation factor which is the slope of the straight line portion of the C_o vs. C_w plots and therefore approximates the intrinsic F for any set of measurement conditions. An Archie type equation therefore exists for shaly sands:

$$F' = \frac{1}{\phi^{m'}} \quad (6)$$

where m' is the cementation factor obtained by correlating F' with ϕ . Similarly, for the hydrocarbon zone, Jing and Archer (1991) modified Waxman and Thomas's (1974) shaly sand equation to account for temperature, pressure and clay distribution effects:

$$S_w^{n'-1} = \frac{F' R_w}{R_t(S_w + \omega B \cdot Q_{ve} R_w)} = \frac{R_w}{\phi^{m'} R_t(S_w + \omega B \cdot Q_{ve} R_w)} \quad (7)$$

where n' is the shaly sand saturation exponent, which depends on rock type, pore fluid distribution and perhaps pressure and temperature. Since for most water-wet reservoir rocks n' equals approximately 2, equation (7) can be simplified where appropriate as follows:

$$S_w = \frac{R_w}{\phi^{m'} R_t(S_w + \omega B \cdot Q_{ve} R_w)} \quad (8.a)$$

or,

$$S_w^2 + \omega B \cdot Q_{ve} R_w S_w = \frac{R_w}{\phi^{m'} R_t} \quad (8.b)$$

So far, routine measurements on core plugs obtained from the formations of interest remain the most reliable source to establish the $\phi - F$ relation for both clean and shaly formations. Since usual laboratory conditions of pressure and temperature may be so different from those *in situ*, understanding the effect of pressure and temperature on $\phi - F$ relationship is of paramount importance.

The effect of pressure and temperature

The effect of confining pressure on Archie formation resistivity factor has been studied by a number of researchers (Fatt, 1957; Wyble, 1958; Glanville, 1959; Redmond, 1962; Helander and Campbell, 1966; Brace *et al.*, 1965; Brace and Orange, 1968; Timur *et al.*, 1972; Parkhomenko, 1982; Longeron *et al.*, 1986; Mahmood *et al.*, 1988; Lewis *et al.*, 1988; Jing *et al.*, 1990). The overwhelming majority of the previous findings support the conclusion that as the confining pressure increases, the formation resistivity factor (F) also increases. Mahmood *et al.* (1988) and Jing *et al.* (1990) also revealed that the Archie cementation factor increases with confining pressure, while Lewis *et al.* (1988) indicated that the increase of cementation factor with confining pressure is not significant.

There are two opposite conclusions in the literature in determining the effect of temperature on Archie formation factor and cementation factor for reservoir rocks. While many authors like Helander and Campbell (1966), Sanyal (1972, 1973), Brannan and von Gonten (1973), and Jing *et al.* (1990) reported an increase in F and m with temperature, some others like Hilchie (1964), Waxman and Thomas (1974), Kern *et al.* (1977), Uco (1982), and Parkhomenko (1982) reported a decrease in F with temperature. This confusion was explained by Jing and Archer (1991) using synthetic shaly rock samples containing various amounts of clay. They concluded that the Archie formation factor and cementation factor may increase or decrease with temperature depending on whether the clay excess conductivity or the thermal expansion effect dominates in a given shaly rock.

Hilchie's work (1964) is one of the few studies concerning the combined effect of pressure and temperature on the electrical properties of reservoir

rocks. He concluded that at low to moderate temperatures, the combined effect of pressure and temperature may be equal to the sum of the two individual effects.

EXPERIMENTAL APPARATUS AND PROCEDURE

An experimental system developed by Integrated Technology Resource Ltd, shown schematically in Figure 1, has been used to measure the electrical properties of rock samples at simulated reservoir conditions. It is a multi-sample rock testing system in which up to five core plugs can be subjected simultaneously to a variable thermostatic formation temperature up to 175 °C, a variable hydrostatic confining pressure up to 34.5 MPa and an independently controllable pore pressure up to 3.5 MPa, to permit both electrical and hydraulic measurements. The use of this multi-sample system enables increase in the rate of data acquisition and, since all five samples are placed in identical conditions, elimination of experimental comparison errors caused by the fluctuations of pressure and temperature.

Figure 2 illustrates schematically the special core sleeve assembly for making synthetic shaly rock samples and to measure the electrical properties using the 4-wire connections at reservoir conditions. The details of a novel experimental procedure of cyclic loading – unloading and heating – cooling developed to consolidate the synthetic rock samples have previously been described in detail by Jing (1990). This laboratory procedure in effect simulates the physical process of sedimentation and compaction of natural sandstone rocks. Loose packs of clay and sand mixtures inside the sample sleeves are first subjected to cyclic loading and unloading (from 0 - 34.5 MPa) then subjected to cyclic heating and cooling (from ambient to 130 °C) until no measurable difference in porosity, electrical resistivity and permeability can be observed among subsequent testing cycles. At this point, the synthetic samples are regarded as consolidated since they behave like consolidated outcrop or reservoir rock samples under pressure and temperature. In our experience it takes about 7 – 10 pressure cycles and 2 – 3 temperature cycles to consolidate the synthetic shaly samples depending on the pressure and temperature increments and the waiting time intervals.

During electrical measurements, readings are taken at each pressure and temperature when the brine level in the calibrated glass burette stops rising and the voltages are stabilised. For the study of hysteresis in both pressure

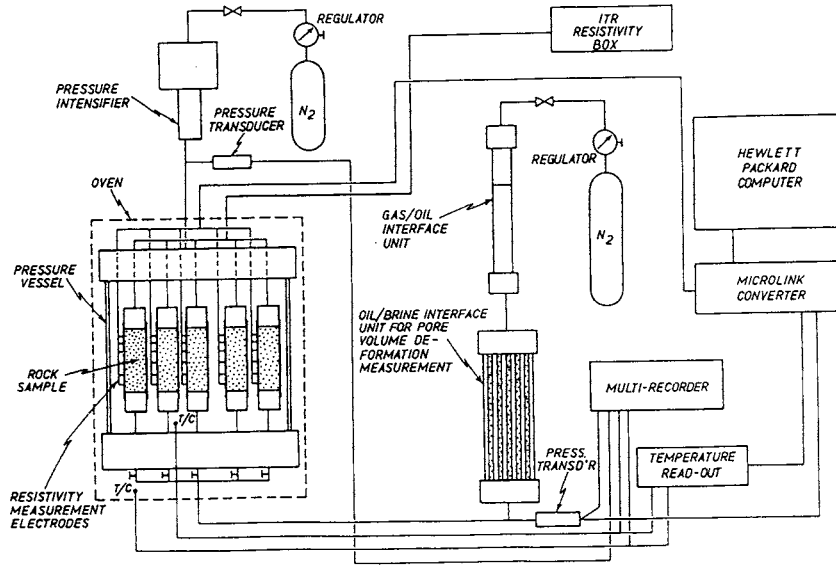


Fig.1 Schematic diagram of the multi-sample high pressure and temperature experimental system

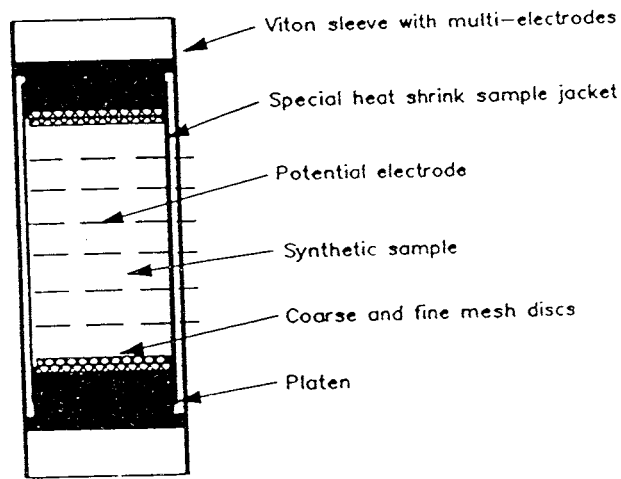


Fig.2 Schematic diagram of the ITR design for making synthetic rock samples

and temperature tests, data are taken in both loading and unloading, or heating and cooling cycles.

RESULTS AND DISCUSSION

For comparison and discussion, the experimental results of clay-free outcrop sandstones (core number starting with S), clay-free reservoir rock samples (core number starting with R), and synthetic shaly samples (core number starting with A) are presented in the following sections. The details of the synthetic shaly samples tested are given in Table 1.

Table 1 : Synthetic Core Sample Information

Core No.	Diameter (cm)	Length (cm)	ϕ (%)	Clay Type	Clay Dist.	Clay Content % weight	Q_v meq/cc
A1	3.567	7.454	29.66			0	0
A2	3.553	7.847	29.85	Mont.*	Dispersed	10	0.240
A3	3.475	6.990	28.86	Mont.	Dispersed	15	0.544
A4	3.331	7.276	25.94	Mont.	Dispersed	20	1.152
A5	3.430	7.500	29.67	Mont.	Dispersed	10	0.297
A6	3.544	6.864	29.46	Kaolinite	Dispersed	10	0.020
A7	3.350	6.714	28.72	Illite	Dispersed	10	0.041
A8	3.420	6.740	28.55	Kaolinite	Dispersed	15	0.044
A9	3.600	6.330	27.72	Illite	Dispersed	15	0.093
A10	3.391	8.157	23.14	Mont.	Dispersed	20	1.053
A11	3.459	8.128	26.56	Mont.	Dispersed	15	0.596
A12	3.489	7.994	28.42	Mont.	Dispersed	15	0.542
A13	3.556	8.185	31.88	Mont.	Laminated	15	0.411
A14	3.499	8.237	31.18	Mont.	Laminated	15	0.477

The effect of confining pressure

Figure 3 shows the formation factors of three rock samples (S1, S2 and R1) against confining pressure. It indicates that F increases significantly with confining pressure over a pressure range from 0 to 30 MPa, and F values

measured in the unloading cycles are higher than those measured in the loading cycles. Similar results were obtained for all the other rock samples.

The reason for the increase in F of various rock samples with pressure appears to be due simply to the compression effect which reduces the pore sizes and changes the tortuosity of current flow paths. The amount of increase in formation factor appears different for different rocks depending upon the porosity, pore geometries, pore size distributions and pore constrictions. The hysteresis observed can be attributed to the "relaxation effect" of rocks under stress.

The experimental results of Archie cementation factor (m) at various confining pressures for samples S1, S2, S3 and R1 are shown in Figure 4. There is a slight increase in m with confining pressure for all the samples tested. Similar to the formation factor plots, there is a noticeable hysteresis effect occurring between the loading and unloading cycles.

The trend towards an increase of the Archie cementation factor with confining pressure indicates that compression of rocks may cause more radical changes in resistivity than does the change in porosity. In other words, the increase of resistivity with confining pressure not only results from the rock deformation but also from other sources such as changes of pore constrictions and perhaps changes in the geometries of the electrochemical double layers associated with clay minerals for shaly sands.

The effect of temperature

As shown in Figure 5, the Archie formation factors of two samples, S1 and S3, increase with temperature and exhibit hysteresis between the heating and cooling cycles. Figure 6 show the results of Archie cementation factor plotted after porosity corrections for samples S1 and S3 at various temperatures from ambient to 160 °C. A hysteresis similar to that in the F versus temperature plot is observed.

The effect of temperature on formation factor and cementation factor of clay-free rocks is attributed to the thermal expansion of rock materials and possibly some permanent pore structure collapses caused by heating and cooling. The change of cementation factor with temperature indicates that thermal effects lead to porosity change as well as pore constriction change.

There are two particular factors influencing the Archie formation factors (apparent formation factors) of shaly rocks at elevated temperatures. One

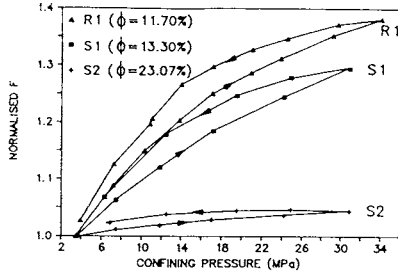


Fig.3 Normalised F vs. confining pressure

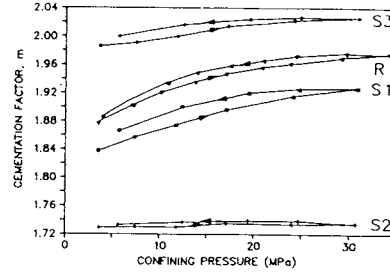


Fig.4 Cementation factor vs. confining pressure

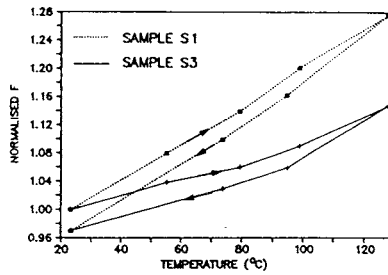


Fig.5 Normalised F vs. temperature for S1 and S3 ($P_c = 13.8$ MPa)

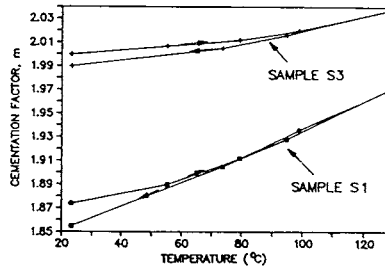


Fig.6 Cementation factor vs. temperature for S1 and S3 ($P_c = 13.8$ MPa)

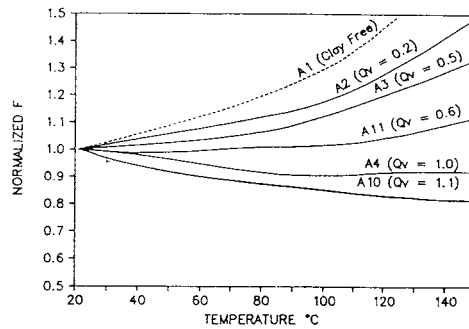


Fig.7 Normalised F vs. temperature for synthetic shaly samples ($P_c = 13.8$ MPa)

is related to the thermal effects including thermal expansion and perhaps pore constriction changes. Another is the electrochemical effect associated with the clay minerals. Theoretically, as the temperature increases, thermal expansion increases the rock resistivity (Hilchie, 1964, Sanyal, 1972, 1973, Brannan and von Gonten, 1973, Uco, 1979, and Jing *et al.*, 1990) while clay excess conductivity reduces the rock resistivity (Waxman and Thomas, 1974, Parkhomenko, 1982). Therefore the total effect of temperature on Archie formation factor depends on which particular factors dominate in a given rock. Figure 7 demonstrates the competing effect between thermal expansion and clay excess conductivity of shaly sands. The normalised Archie formation factor, obtained from the heating cycle, is plotted against temperature for six synthetic samples with various amounts of uniformly dispersed montmorillonite clay (except A1 which is clay-free). As the clay content increases, the curves of normalised F *vs.* temperature shift down, then pass through a minimum around $Q_v = 0.8$, where the clay excess conductivity is balanced by the thermal expansion effect. Above the critical clay content the trend of F against temperature changes as shown in Figure 7 for sample A4 and A10. Therefore, the decrease in apparent formation factor with temperature appears to be a result of the domination by clay effects as in the cases of A4 and A10, which have relatively high clay contents.

The coupled effect of pressure and temperature

Experiments have been carried out on 5 sandstone rock samples, namely S1, S2, S3, S4 and S5, to investigate the Archie formation factor and cementation factor at coupled high pressure and temperature conditions. Figure 8 shows a plot of F against pressure along the x - axis and against temperature along the y - axis for sample S1 in a three dimensional view. Similar results of Archie cementation factor *vs.* coupled pressure and temperature have been obtained for the 5 rock samples. The results obtained agree with Hilchie's report showing that the combined effect of pressure and temperature on the electrical properties of these sandstone rocks tested is approximately the sum of their individual effects.

The effect of temperature on clay excess conductivity

Multiple-salinity measurements have been performed on shaly-sand cores (A2, A3, A4 and A5) containing various clay concentrations (Q_v) varying

from 0.240 to 1.152 meq/cc. These cores were equilibrated with three *NaCl* brine solutions: 120, 50 and 20 grams/litre. The electrical conductivities were measured at five temperatures: 22.1, 55.7, 76.3, 99.2 and 127.5 °C.

The electrical conductivity measurements were carried out with the samples maintained at a net confining pressure of 6.9 MPa (1,000 psi), consisting of a fixed external pressure of 8.3 MPa (1,200 psi) on the rock matrix and 1.4 MPa (200 psi) on the internal aqueous phase. Resistance equilibrium (less than 0.5% variation in resistance) after each temperature increment was obtained by waiting for about 12 hours (over-night).

Figures 9 – 10 show the electrical conductivities of samples A3 and A5 *vs.* equilibrating brine conductivities at various temperatures. As temperature increases, the slopes of the straight line portions of the C_o *vs.* C_w curves decrease while the C_o intercepts obtained by extrapolation of the straight-line portions of the conductivity curves to zero C_w , increase with temperature. The decrease in the slope further indicates the increase of the shaly sand formation factor with temperature as a result of thermal effect. The increase in the C_o intercept with temperature reveals that the equivalent conductance of the clay counterions increases with temperature accordingly. This increase in equivalent clay counterion conductivity with temperature may be attributed to the increase in the ion mobility within the layer of clay bound water. Therefore, these C_o *vs.* C_w plots at various temperatures not only show the clay effect on the shaly sand conductivity by the C_o intercepts but also show the thermal effect by the slopes of the straight line portions.

The temperature coefficient (ω) in equation (5) was defined as the ratio of the equivalent conductance of the clay counterions at elevated temperatures over that at room temperatures (*e.g.*, 22 °C). Figure 11 shows the experimentally determined values of ω at various temperatures with effective clay content (Q_v) ranging from 0.240 to 1.152 meq/cc. The following generalised observations may be made after inspecting the experimental results.

- (i) The temperature coefficient (ω) for the equivalent conductance of clay counter-ions increases with temperature.
- (ii) The increase of ω with temperature is more significant for shaly sands with relatively small effective clay content (Q_v).

Observation (i), which may be attributed to the increase in the ion mobility with temperature, agrees with the experimental results reported by Waxman and Thomas (1974). Observation (ii), however, reveals an inter-

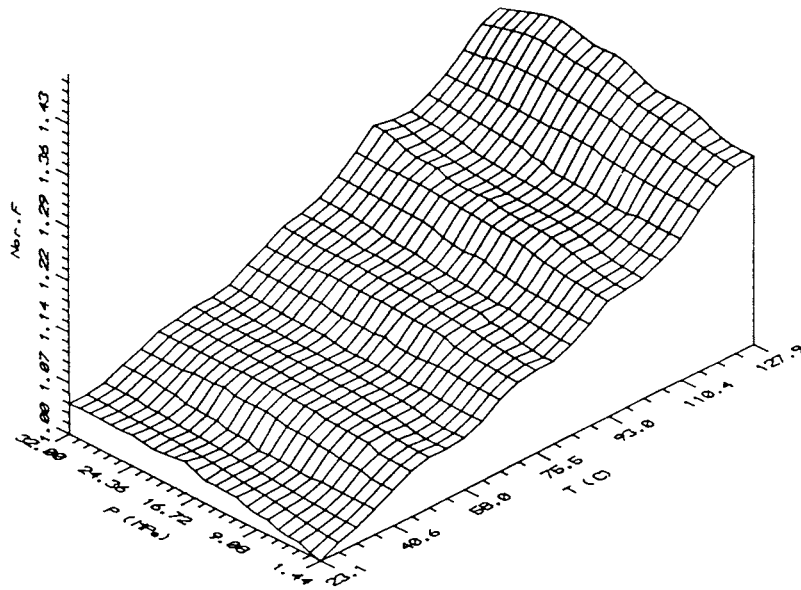


Fig.8 F vs. coupled pressure and temperature (S1)

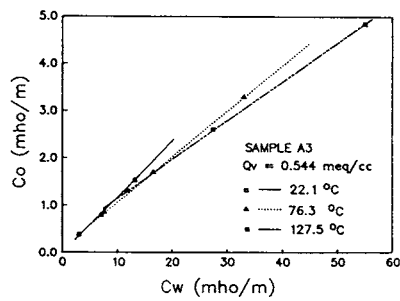


Fig.9 C_o vs. C_w at various temperatures for sample A3 ($P_c = 6.9$ MPa)

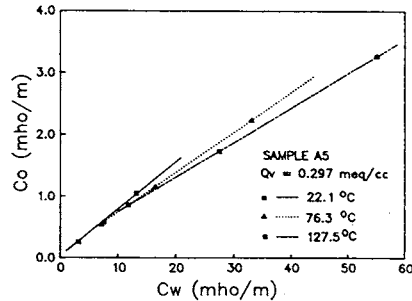


Fig.10 C_o vs. C_w at various temperatures for sample A5 ($P_c = 6.9$ MPa)

esting new aspect of the conductive behaviour of shaly rocks at elevated temperatures. The less significant increase in ω with temperature for more shaly rocks may be due to the limitation in the increase of ion mobility with temperature as a result of the interaction among the highly concentrated ions. The interference between neighbouring electrical double layers within the very shaly rocks may also contribute to the above observation (ii). It may be predicted that as Q_v decreases further to below 0.2 meq/cc, the curves of ω vs. temperature as shown in Figure 11 will become independent on Q_v . This is because, for those shaly sands with very small Q_v , the interaction among ions in the double layers and the interference between neighbouring double layers are no longer significant.

So far, the effect of pressure on clay excess conductivity has generally been neglected due to the lack of appropriate experimental measurements. Further work in progress includes both the experimental (multiple-salinity) and numerical (pore space network model) study of the confining and pore fluid pressure effect on clay excess conductivity of shaly sands.

The effect of clay distribution on shaly sand conductivity

Four shaly samples with similar clay contents but different clay distribution modes were chosen in this study. These are A3 and A12 (with dispersed clay), A13 (laminated clay with layers parallel to flow) and A14 (laminated clay with layers perpendicular to flow). We define two terms "Degree of Dispersion (*DOD*)" and "Degree of Lamination (*DOL*)" to describe the fraction of the clay volume per unit volume of reservoir rock for dispersed or structural and laminated clay distribution respectively.

Figure 12 shows the C_o vs. C_w curves determined experimentally (symbols) and fitted by the Waxman-Smits model (lines) for 4 shaly samples (A3, A12, A13 and A14). The experimental data were modelled by varying the input values of Q_v used until the best fit was achieved. The final input value of Q_v is defined as "effective clay concentration" and represented by a new symbol Q_{ve} , which may be determined experimentally by the "multiple-salinity method" or the "membrane-potential method". In order to relate Q_{ve} to Q_v from *CEC* measurements, a clay distribution coefficient $\tau = \frac{Q_{ve}}{Q_v}$ was defined by Jing (1990). A 3D pore space computer model (Jing *et al.*, 1990) has been developed to calculate the clay distribution coefficient (τ) for the generated stochastic clay distributions. Figures 13 and 14 give the

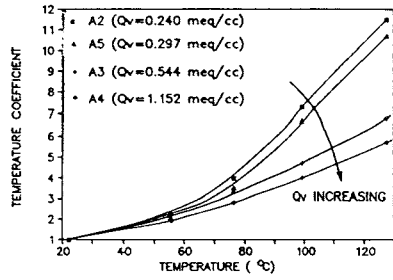


Fig. 11 Temperature coefficient (ω) vs. temperature and clay content (Q_v)

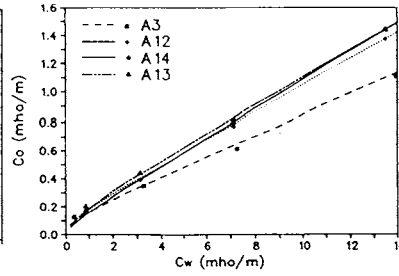


Fig. 12 C_o vs. C_w for shaly samples showing the effect of clay distribution ($P_c = 6.9$ MPa)

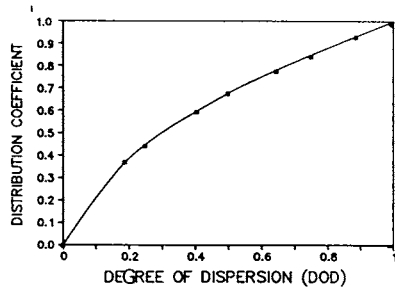


Fig. 13 Simulation results of distribution coefficient (τ) vs. DOD

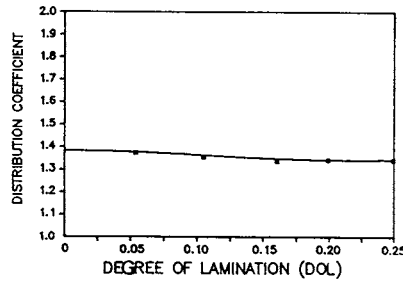


Fig. 14 Simulation results of distribution coefficient (τ) vs. DOL

values of τ as a function of clay volume fractions, DOD and DOL for dispersed and laminated clay distributions respectively. For structural clay, it is believed that the value of τ is similar to that of dispersed clay with the same DOD .

It is concluded that if values of Q_v derived from the conventional conductometric titration, or CEC , measurements are used in the interpretation of shaly sands, which ignores the influence of clay distribution, total clay effect can be under-estimated for laminated clay distribution where the shale layers are parallel to the flow direction, while for dispersed and structural clay, total clay effect can be over-estimation depending on the degree of dispersion (DOD). For laminated clay distributions with shale layers perpendicular to the flow direction, the clay effect on shaly sand conductivity is likely to be overestimated.

PARAMETRIC STUDY

A parametric study, which is based on our bank of experimental data and the improved shaly-sand conductivity model, demonstrates the influences of pressure, temperature and clay excess conductivity upon the determination of *in situ* water and hydrocarbon saturations from the electric resistivity logs. The details of this parametric study are presented in the Appendix.

CONCLUSIONS

- (1) Significant increases in formation factor with pressure and temperature have been observed for both clay free and shaly rocks. The trend towards an increase of cementation factor with pressure and temperature has been observed for those low porosity and low permeability rocks.
- (2) The combined effect of pressure and temperature on the electrical properties of these sandstone rocks tested is found to be approximately the sum of their individual effects.
- (3) Ignoring the effect of pressure and temperature on cementation factor for both clean and shaly rocks leads to over-estimations of the uninvasion zone oil saturations for a wide range of sandstone formations. The degree of these over-estimations caused by ignoring pressure and temperature effects, however, is found to be more pronounced for those low porosity and low permeability rocks.
- (4) An improved Waxman-Smits shaly sand conductivity model has been

proposed to account for the effect of pressure, temperature and clay distribution. To ensure the reliable calculation of *in situ* hydrocarbon saturations of shaly formations, the effect of pressure and temperature on the shaly cementation factor (m') and clay excess conductivity, and the effect of clay distribution should be considered.

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APPENDIX: PARAMETRIC STUDY

Example 1

This example shows the differences in calculated virgin zone water saturation (S_w) and flushed zone moved oil saturation (S_{mo}) for two hypothetical formations in an oil reservoir when the effect of confining pressure and temperature on cementation factor (m) is ignored during the establishment of the $F - \phi$ equation in the laboratory.

The effect of confining pressure

FORMATION S1

DEPTH:	2307 m	R_w :	0.07 ohm-m
TEMP.:	98.8 °C	R_{mf} :	0.29 ohm-m
ϕ :	12.7%	n :	2.0
R_t :	55.80 ohm-m	m (room):	1.838
R_{xo} :	52.00 ohm-m	m (30 MPa):	1.928

Before considering the effect of confining pressure, the water saturation of the non-invaded zone is calculated with equation (3):

$$S_w = \sqrt{\frac{0.07}{0.127^{1.838} \times 55.8}} = 0.236$$

Using equation (4), the mud filtrate saturation of the invaded zone can be calculated:

$$S_{xo} = \sqrt{\frac{0.29}{0.127^{1.838} \times 52.0}} = 0.498$$

Therefore, the mobile oil saturation:

$$S_{mo} = 0.498 - 0.236 = 0.262$$

After considering the effect of confining pressure on cementation factor, the water saturation of the non-invaded zone can be calculated:

$$S_w = \sqrt{\frac{0.07}{0.127^{1.928} \times 55.8}} = 0.259$$

Similarly, the mud filtrate saturation of the invaded zone can be calculated:

$$S_{xo} = \sqrt{\frac{0.29}{0.127^{1.928} \times 52.0}} = 0.546$$

The mobile oil saturation after considering confining pressure is:

$$S_{mo} = 0.546 - 0.259 = 0.287$$

Therefore, if the effect of confining pressure on the cementation factor, or the $F - \phi$ relation, is ignored for formation S1, the calculated uninvaded zone oil saturation can be over-estimated by 2.3% of the total pore volume, while the flushed zone moved oil saturation can be under-estimated by 2.5% of the total pore volume.

The effect of temperature

m (room temperature):	1.928
m (reservoir temperature):	1.992

If all the parameters are kept constant, with the exception of the cementation factor from room to reservoir temperature as shown above, the following results are obtained:

m (room temp.)	m (reservoir temp.)
S_w : 0.259	S_w : 0.277
S_{xo} : 0.546	S_{xo} : 0.583
S_{mo} : 0.287	S_{mo} : 0.306

Therefore, if the effect of temperature on the cementation factor, or the $F - \phi$ relation, is ignored for formation S1, the calculated uninvaded zone oil saturation can be over-estimated by 1.8% of the total pore volume, while the flushed zone mobile oil saturation can be under-estimated by 1.9% of the total pore volume. If the coupled effects of pressure and temperature on the cementation factor are ignored for formation S1, the calculated uninvaded zone oil saturation and the flushed zone moved oil saturation can be over-estimated or under-estimated by 4.1% and 4.4% of the total pore volume, respectively.

FORMATION S2

DEPTH:	2307 m	R_w :	0.07 ohm-m
TEMP.:	98.8 °C	R_{mf} :	0.29 ohm-m
ϕ :	22.8%	n :	2.0
R_t :	17.5 ohm-m	m (room):	1.730
R_{xo} :	13.6 ohm-m	m (reservoir):	1.807

The following calculations are based on the experimental results of sample S2 which is more porous and permeable than S1 discussed above. Following the same calculation procedures as described for formation S1, the saturations of formation S2 calculated before and after considering the effects of pressure and temperature are shown as follows:

m (room con.)	m (reservoir con.)
S_w : 0.227	S_w : 0.241
S_{xo} : 0.525	S_{xo} : 0.555
S_{mo} : 0.298	S_{mo} : 0.314

Therefore, if the coupled effects of pressure and temperature on the cementation factor are ignored for formation S2, the calculated uninvasion zone oil saturation and the flushed zone moved oil saturation can be over-estimated or under-estimated by 1.4% and 1.6% of the total pore volume, respectively. Compared to formation S1, however, the difference in the calculated oil saturations is relatively less significant. Similar observations can be made based on the results obtained from other sandstone rocks.

Example 2

This example shows the clay effect on the calculation of uninvasion zone water saturations (S_w) for two hypothetical shaly formations in an oil reservoir. The quantitative influences of the two new factors (*i.e.*, ω and τ) in the new shaly sand conductivity model proposed by Jing and Archer (1991), are demonstrated in the following case studies.

FORMATION A3

DEPTH:	2500 m	R_w :	0.07 ohm-m
TEMP.:	120.0 °C	$Q_v(CEC)$:	0.544 ohm-m
F' :	12.0	B (room):	0.0343 $\frac{cm^2}{ohm \cdot meq}$
R_t :	3.8 ohm-m	n :	2.0

FORMATION A5

DEPTH:	2500 m	R_w :	0.07 ohm-m
TEMP.:	120.0 °C	$Q_v(CEC)$:	0.297 ohm-m
F' :	15.4	B (room):	0.0343 $\frac{cm^2}{ohm \cdot meq}$
R_t :	7.3 ohm-m	n :	2.0

The effect of temperature on clay excess conductivity

Based on the original Waxman-Smits model, assuming that the constant B changes with temperature as given by Waxman and Thomas (1974) in Figure 13 of their paper, the saturation of the virgin zone can be calculated as S_w (W-S). Using equation (8) and reading the value of ω from Figure 11 of this study, the water saturation can be calculated as S_w (J-A). The following is a comparison of the calculated water saturations using the original and the improved Waxman-Smits models respectively, showing the effect of temperature on clay excess conductivity:

Formation	S_w (W-S)	S_w (J-A)
A3	0.227	0.211
A5	0.229	0.172

For the two shaly formations discussed, the original W-S model underestimates the oil saturations. This under-estimation as a result of temperature effect is more significant for shaly sands with relatively small clay content (Q_v).

The effect of clay distribution

Using the improved Waxman-Smits shaly sand conductivity model (equation 8), the following case study has been carried out to show the differences in calculated water saturations for formation A3 assuming the same bulk clay content, but various distribution types. The clay distribution coefficient (τ) is obtained from Figures 13 and 14 of this study.

Clay Dist.		S_w
Disp. or Struc.	$DOD = 1.00$	0.211
Disp. or Struc.	$DOD = 0.75$	0.255
Disp. or Struc.	$DOD = 0.50$	0.287
Laminated	thin layers	0.190

Therefore, this quantitative study supports the conclusion that if values of Q_v derived from CEC measurements are used in the interpretation of shaly sands, which ignores the influence of clay distribution, total oil saturation can be under-estimated for laminated clay distribution where the shale layers are parallel to the flow direction. For dispersed and structural clay, however, the oil saturation is likely to be over-estimated depending on the volume fractions of clays in unit volume of rocks (DOD).