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THE ANALYSIS OF RESERVOIR HETEROGENEITY FROM WELL LOG DATA

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Abstract: All reservoirs are characterized by a sum of matrix and fluids properties. They are evaluated by a complex investigation consisting of core sampling analysis, geological, geophysical and hydrodynamic investigation and production data. These properties can be constant for the whole field when the reservoir is a homogenous one, or these properties can be variable and the reservoir is a heterogeneous one. But, what is the reservoir heterogeneity and how we can find its magnitude? According to Jensen et al (1997), “Heterogeneity is the property of the medium that causes the flood front, the boundary between the displacing and displaced fluids, to distort and spread as the displacement proceeds”. There are more statistics methods (static and dynamic) for determination of reservoir heterogeneity. The static methods are: The Coefficient of Variation, Dykstra-Parsons Coefficient, Lorenz Coefficient and Gelhar-Axness Coefficient. This work is focused on the static methods, more specifically on Lorenz coefficient, while the dynamic methods are not discussed. For calculation the Coefficient Lorenz is necessary to know porosity, permeability and thickness of the reservoir. The number of values has to be enough and have a uniform distribution on the field for a statistical calculus. The following aspects of this application are emphasizing: wide domain of values for permeability data, the number of permeability values is not always enough for statistical analysing methods; the parameters from well logs are more representative and easy to obtain for the whole reservoir. This paper presents a new mathematical model and a novel practical method to evaluate the reservoir heterogeneity with Lorenz Coefficient using properties of rocks determined from well logs. The mathematical model uses field parameters, such as reservoir porosity, porosity of shale, shale volume and thickness to evaluate the reservoir heterogeneity. The technical contribution of this paper consists not only in a novel practical method to evaluate reservoir heterogeneity, but new challenges are expected from a technological point of view. The application data are provided by the wells from the oil structure named Barbuncesti, (Beca, C., Prodan, D., 1983.) Barbucesti structure is situated in the southern part of the inner (folded) flank of the Eastern Carpathians foredeep known as the Miopliocene or Diapiric Folds Zone.

Keywords: heterogeneity, porosity, permeability, clay volume, Lorenz Coefficient

1. Introduction

A good management of oil and gas fields is given by the data accuracy contained in the geological documentation, physical model of reservoir, history matching etc. A comprehensive and detailed study of the reservoir rocks and their fluids (Davis, 1973) is essential to optimize oil and gas recovery and maximize income. Geological and geophysical data are essential elements of most aspects concerning reservoir description. The initial data for an oil reservoir exploitation study (Dake, 1978) are obtained from: well logs, samples from wells (cores, cuttings, lateral samples, DST, etc.), production data, and hydrodynamic investigations.

The physical model contains data regarding: reservoir’s depth, collectors’ thickness, porosity, permeability, formation pressure, temperature etc. These values are obtained from well measurements and represent individual point values with a not necessarily uniform spatial distribution, both horizontal and vertical. Data uniformity determines the collectors’ homogeneity or heterogeneity.

Heterogeneity measures can be classified as static and dynamic. The static measure of heterogeneity takes into account statistically the directly or indirectly measured values on formation samples, the dynamic measure of heterogeneity implying a flow experiment and evaluating how the heterogeneity affects the flow.

Reservoir properties such as porosity, permeability, clay volume, and water saturation are probabilistic in nature at a small scale, but deterministic in behaviour at a large scale. They have a major influence on fluid accumulation into the reservoir and on the fluid flow through the porous media.
Similarly, the collectors' heterogeneity values lead to reservoir's management decisions like the opportunity of drilling horizontal wells, use of secondary recovery processing, performing raising afflux from the collector to the wells etc.

Using quantitative methods for finding the collectors' heterogeneity allows for the right decisions in its exploitation.

Apart from the Lorenz Coefficient, worth to be mentioned is the Coefficient of Variation, the Dykstra–Parsons and the Gelhar–Axness ones.

Coefficient of Variation
The coefficient of variation is given by relation:

$$C_V = \frac{S}{\overline{X}} \quad 100 \quad (1)$$

where S is the standard deviation and $\overline{X}$ is the arithmetic average.

The mean and standard deviation tend to change together while the coefficient of variation tends to remain relatively constant. If the data are a reservoir's property, the coefficient of variation may indicate its heterogeneity (Moissis and Wheeler, 1990).

Dykstra – Parsons Coefficient

One of the most important properties of the reservoirs is permeability. Although the permeability is an important measure in reservoir engineering, its values obtained using direct (samples measurements) or indirect (hydrodynamic investigations) methods have large variations. The heterogeneity of reservoirs' permeability is given by the Dykstra–Parsons' Coefficient (Dykstra and Parsons, 1950):

$$V_{DP} = \frac{k_{0.50} - k_{0.16}}{k_{0.50}} \quad (2)$$

where $k_{0.5}$ in the permeability median value while k_{016} is the permeability one standard deviation below $k_{0.5}$ on a log-probability plot (Dykstra and Parsons, 1950).

V_{DP} is null for homogeneous reservoirs and one for hypothetically „infinitively" heterogeneous ones. This coefficient is also known as permeability variation coefficient, variance or variation.

Gelhar – Axness coefficient

The Gelhar – Axness coefficient (Gelhar and Axness, 1983) is a combination of static measures and spatial correlation and is given by:

$$I_H = \sigma^2_{\ln(k)} \times \lambda_D \quad (3)$$

where $\sigma^2_{\ln(k)}$ is the variance and λ_D is the autocorrelation length.

2. Lorenz Coefficient

The Lorenz heterogeneity coefficient is a static measure of heterogeneity taking into consideration the statistic nature of the porosity and of the permeability of a stratified reservoir consisting of N sub layers of net pay thickness h_i, K_i absolute permeability and Φ_i absolute porosity. For every $1 \le n \le N$, the fractional flow capacity, F_n, is evaluated as:

$$F_n = \frac{\sum_{j=1}^{n} K_j \cdot h_j}{\sum_{j=1}^{N} K_j \cdot h_j} \quad (4)$$

and the fractional storage capacity, C_n, as:

$$C_n = \frac{\sum_{j=1}^{n} \Phi_j \cdot h_j}{\sum_{j=1}^{N} \Phi_j \cdot h_j} \quad (5)$$

One can plot F versus C on a linear graph (Fig.1), and connect the points to form the Lorenz curve BCD. The curve must pass through (0,0) and (1,1). If A is the area between the curve and the diagonal, the Lorenz coefficient is defined as L_C= 2A. Using the trapezoidal integration rule, we have (Jensent and Lake, 1991):

$$L_C = \frac{1}{(I-1)^2 \sum_{i=1}^{I} \frac{k_i}{\Phi_i}} \sum_{i=1}^{I} \sum_{j=1}^{J} \left| \frac{k_i}{\Phi_i} - \frac{k_i}{\Phi_i} \right| \quad (6)$$

The Lorenz Coefficient is null for homogeneous reservoirs and one for hypothetically „infinitively" heterogeneous ones. The Lorenz Coefficient can be computed with a good accuracy for any oil field if the thickness, porosity and permeability are correctly determinated. Between these three properties, usually, the permeability has a large domain of values, the amplitude of this property's values is wide and the accuracy of determinations is not always very good.

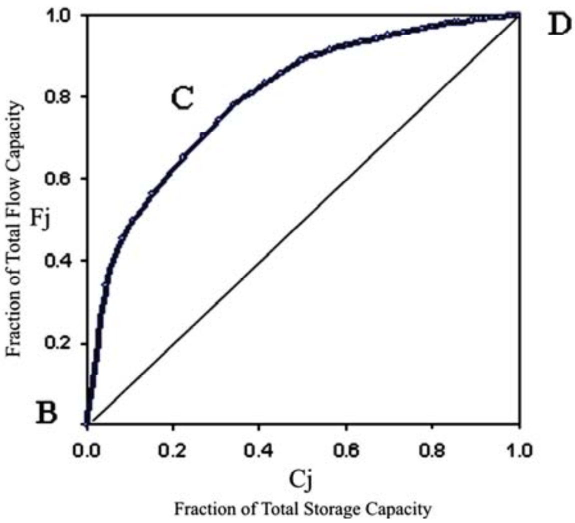

Fig. 1. Total flow capacity F_j vs. total storage capacity C_j Lorenz coefficient = 2 x Area BCDB.

In this paper we propose to compute the Lorenz coefficient using the data from well logs. The thickness and the porosity are two properties which are easy to obtain from well logs, (Djebbar and Donaldson, 2004) compensated neutron log, density log, sonic log and other methods.

A special problem is the values of permeability for which were established many empirically relations. The absolute values of permeability compute with these relations are not always satisfactory because the precision is not very good. To calculate the fractional flow capacity, F_n , we can use relatively values, so we present further on.

Based on the relation of Wyllie and Rose (1950) were propose a few empirically relations for evaluate the permeability *"k"* which use the porosity *"Φ "* and irreducible water saturations *"S_{wi}"*, both properties can be obtained from well logs. The most well know relations (Schlumberger Ltd., 1989) are:

Tixier

$$k^{1/2} = 250 \cdot \frac{\Phi^3}{S_{wi}} \quad (7)$$

Timur

$$k^{1/2} = 100 \cdot \frac{\Phi^{2.25}}{S_{wi}} \quad (8)$$

Coates-Dumanoir

$$k^{1/2} = \frac{300}{w^4} \cdot \frac{\Phi^w}{S_{wi}^w} \quad (9)$$

Coates

$$k^{1/2} = 70 \cdot \frac{\Phi_e^2 \cdot (1 - S_{wi})}{S_{wi}} \quad (10)$$

where, Φ_e is the effective porosity

Further on we are using Coates's relation in which change the effective porosity with the relation used in interpretation of well logs (Djebbar and Donaldson, 2004):

$$\Phi_e = \Phi - V_{sh} \cdot \Phi_{sh} \quad (11)$$

In the relation (11) "V_{sh}" and "Φ_{sh}" are volume and porosity of shale. Both volume and porosity of shale can be obtained from the well logs.

After the calculations were done, we obtained:

$$k^{1/2} = 70\frac{\Phi^2(1-S_{wi})}{S_{wi}} - 70\frac{\Phi^2(1-S_{wi})}{S_{wi}} \times \frac{2\cdot\Phi_{sh}}{\Phi}V_{sh} + 70\frac{\Phi_{sh}^2(1-S_{wi})}{S_{wi}} \times V_{sh}^2 \quad (12)$$

We made the following notations:

$$k_0^{1/2} = 70 \cdot \frac{\Phi^2 (1 - S_{wi})}{S_{wi}} \quad (13)$$

$$R_P = \frac{2 \cdot \Phi_{sh}}{\Phi} \quad (14)$$

$$k_{sh}^{1/2} = 70 \cdot \frac{\Phi_{sh}^2 (1 - S_{wi})}{S_{wi}} \quad (15)$$

We replace into the relation (12) the relations (13), (14) and (15) and obtain:

$$k^{1/2} = k_0^{1/2} - k_0^{1/2} \cdot R_P \cdot V_{sh} + V_{sh}^2 \cdot k_{sh}^{1/2} \quad (16)$$

The shale has permeability very small near zero (Darling, 2005) so the permeability of shale given by the relation (15) can be taken equal with zero, therefore the relation (16) becomes:

$$k^{1/2} = k_0^{1/2} (1 - R_P \cdot V_{sh}) \quad (17)$$

The fractional flow capacity, F_n, given by relation (4), becomes:

$$F_j = \frac{\sum_{j=1}^{n} (1 - R_{Pj} \cdot V_{shj})^2 \cdot h_j}{\sum_{j=1}^{N} (1 - R_{Pj} \cdot V_{shj})^2 \cdot h_j} \quad (18)$$

Using the relations (18) and (5) we can calculate the Lorenz Coefficient only with data from the well logs (porosity, porosity of shale, shale volume and thickness of the bed)

3. Application

The application was made on the Barbuncesti structure. From stratigraphical point of view occur miocene and pliocene deposits with a cumulative thickness about 3500 meters. They are developed in a detritic faices forming an alternance of pellitic and arenitic rocks as: sandstones, sands and shales. Barbuncesti structure is an asymmetric anticline oriented NE – SW affected by longitudinal and transversal faults which divides it in different tectonic sealed blocks forming distinct hydrodynamic units. Its size is about 6 km length and 2 km wide. The traps are structural (fault seal) type.

The main petroleum accumulations are hosted by upper miocene reservoirs. These deposits (about 600–800m thick) are separated in 8 productive complexes.

There were selected four wells A, B, C, D and only one porous - permeable layer (layer 2).In these wells were recorded the following logs: dual - laterolog (DLT), density log, neutron log, sonic log and gamma ray. The qualitative interpretation of well logs shows the heterogeneity of the layer 2 in vertical and horizontal planes.

The correlation of the wells A, B, C, D is shown in Fig. 2. All reservoir properties need to calculate the Lorenz Coefficient were determined using the Interactive Petrophysics Software from Schlumberger. The values of these properties were obtained at a step equal with 0.1m on the depth scale. The porosity of bed and porosity of shale were determined from density log, neutron log and sonic log, and volume of shale from gamma ray (Schlumberger Ltd., 1989, 1996). For each well, the evaluation of heterogeneity of the complex 2 was calculated with the relations (18), (5) and (6). Because the thickness is constant, equal with 0.1m, the relation (18), become:

$$F_j = \frac{\sum_{j=1}^{n} \left(1 - R_{Pj} \cdot V_{shj}\right)^2}{\sum_{j=1}^{N} \left(1 - R_{Pj} \cdot V_{shj}\right)^2} \qquad (19)$$

The number of input data for calculus the parameters C_j and F_j are: well A – 171, B – 191, C – 291, and D – 261. An example of format for input data is given in table 1, for well A. With these data the heterogeneity of reservoir for wells A, B, C, and D were calculated. Lorenz Coefficient plots are shown in fig. 3, 4, 5, and 6.

For the whole oil field we have cumulated all data from each well, and calculated the value of Lorenz Coefficient, (Fig. 7). The numerical values of the Lorenz Coefficient are presented in table 1.

The value of Lorenz Coefficient obtained for the whole oil field is approximately equal with the arithmetic average of Lorenz Coefficient values for each well:

$$L_C = \frac{\sum_{i=1}^{w} L_{ci}}{w} \qquad (20)$$

where - w- is the number of the wells

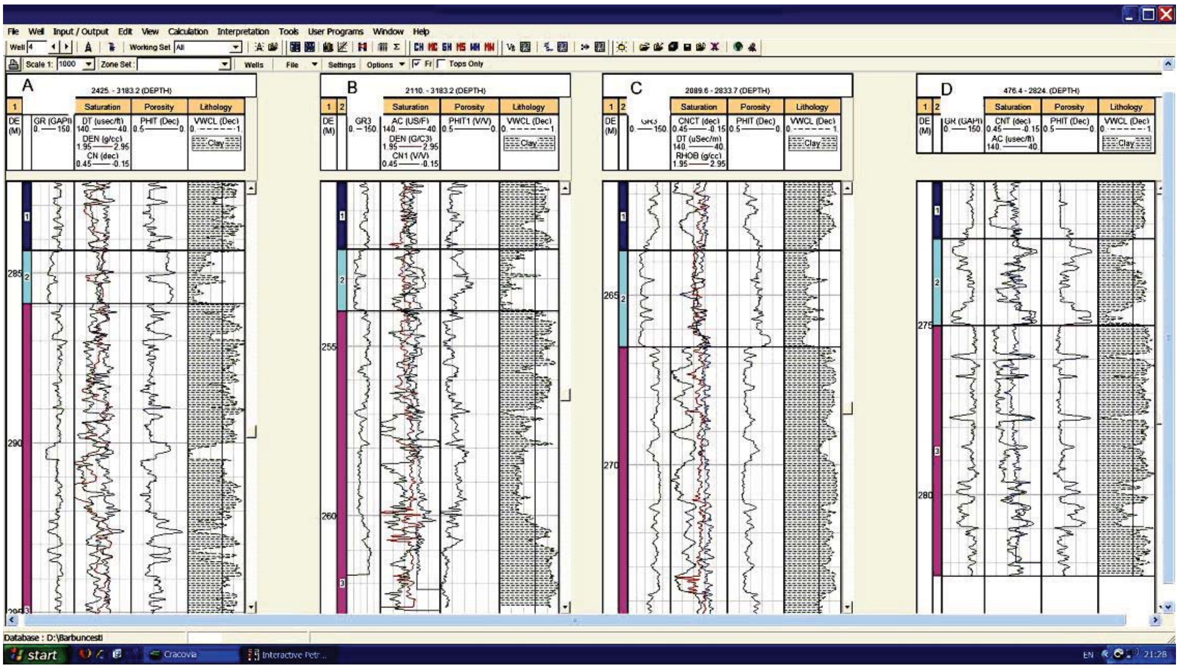

Fig. 2. Correlation of log for wells A, B, C and D.

In order to validate of the results from the well logs and the relation with which the F_j parameter was computed, for the same field, we have computed the Lorenz Coefficient based on the porosity and permeability from samples with relations (4) and (5). The initial data listed are in table 2 and the result is shown in fig. 8. The value of the Lorenz Coefficient is 0.37. The values of Lorenz Coefficient are: 0.48 from well logs and 0.37 for the samples, which represent a difference by 0.11.

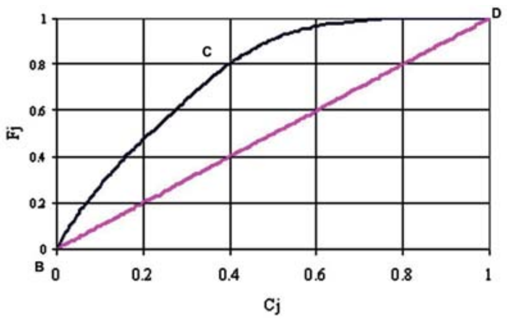

Fig. 3. Lorenz Coefficient for well A, L_C=0.516

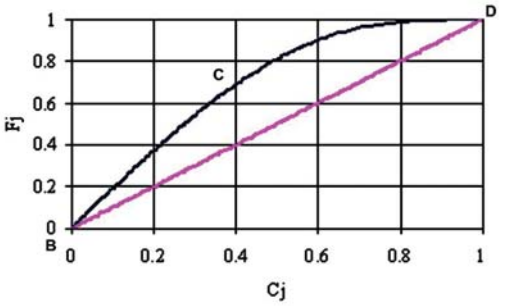

Fig. 4. Lorenz Coefficient for well B, L_C=0.392

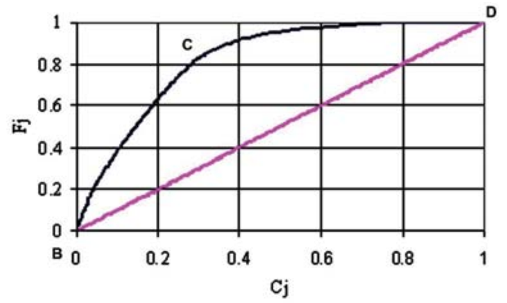

Fig. 5. Lorenz Coefficient for well C, L_C=0.642

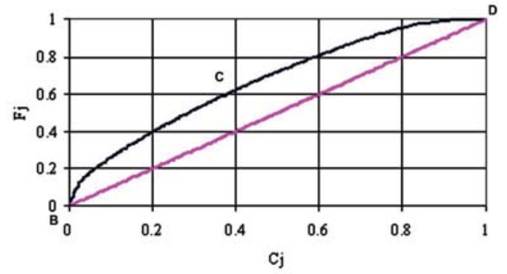

Fig. 6. Lorenz Coefficient for well D, L_C=0.332

Table 1. Values of Lorenz Coefficient for wells and "Barbuncesti Field" from well log

No	Name of well	Lorenz Coefficient "L_C"
1	A	0,516
2	B	0,392
3	C	0,642
4	D	0,332
5	"Barbuncesti Field"	0,478

4. Conclusion

Determination of reservoir heterogeneity based on Lorenz Coefficient with this methodology, shown above consist of calculating the fractional flow capacity, F_n with relation (18), which is not directly dependent of the permeability. Both parameters C_j and F_j are function of reservoir porosity "Φ", shale porosity "Φ_{sh}", volume of shale "V_{sh}", and thickness "h" of reservoir. All these properties can be determined from well logs with a very good precision and have the advantage, that at least regarding the degree of precision, the density and continuity of data, are net superior at those obtain from the samples.

For determination "Φ", "Φ_{sh}" we can use density log, neutron log and sonic log and "V_{sh}" was obtained from gamma ray. The thickness "h" can be obtained directly by measuring on the diagraphies, or put the condition $V_{sh} \leq 40\,\%$and selecting only

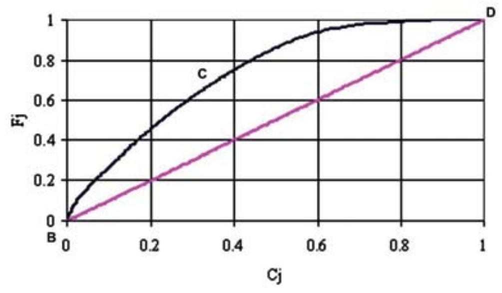

Fig. 7. Lorenz Coefficient from well log for "Barbuncesti Field ", L_C=0.478

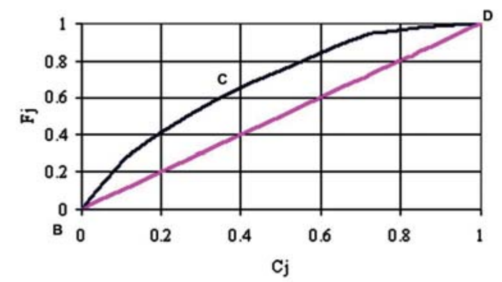

Fig. 8. Lorenz Coefficient from samples for "Barbuncesti Field", L_C=0.37

Table 2. Example of input data format for well A

WELL A							
DEPTH	*GR*	*Porosity*	*Shale volume*	*DEPTH*	*GR*	*Porosity*	*Shale volume*
(m)	*(GAPI)*	Φ (dec)	V_{sh} *(dec)*	*(m)*	*(GAPI)*	Φ (dec)	V_{sh} *(dec)*
2843,00	105,89	0,361	0,902	2845,10	682,52	0,185	0,294
2843,10	106,94	0,367	0,918	2845,20	687,19	0,187	0,302
2843,20	105,78	0,360	0,900	2845,30	690,83	0,189	0,308
2843,30	103,71	0,347	0,866	2845,40	680,93	0,186	0,292
2843,40	102,95	0,342	0,854	2845,50	66,18	0,179	0,261
2843,50	103,76	0,347	0,867	2845,60	645,88	0,172	0,235
2843,60	996,97	0,321	0,802	2845,70	650,06	0,169	0,242
2843,70	897,62	0,257	0,641	2845,80	669,11	0,171	0,273
2843,80	79,00	0,187	0,468	2845,90	683,90	0,173	0,297
2843,90	724,76	0,163	0,363	2846,00	687,43	0,174	0,302
2844,00	725,53	0,168	0,364	2846,10	68,19	0,173	0,293
2844,10	733,44	0,173	0,377	2846,20	677,53	0,172	0,286
2844,20	734,88	0,176	0,379	2846,30	683,67	0,172	0,296
2844,30	739,06	0,179	0,386	2846,40	702,74	0,175	0,327
2844,40	747,93	0,183	0,400	2846,50	706,24	0,173	0,333
2844,50	746,46	0,185	0,398	2846,60	708,21	0,170	0,336
2844,60	724,45	0,182	0,362	2846,70	724,45	0,171	0,362
2844,70	706,87	0,181	0,334	2846,80	748,31	0,176	0,401
2844,80	694,15	0,180	0,313	2846,90	747,96	0,177	0,400
2844,90	687,21	0,181	0,302	2847,00	742,21	0,177	0,391
2845,00	682,25	0,183	0,294				

the intervals according to this condition. These properties can be obtained from only two logs, neutron log (CNL) and gamma ray (GR). This is very important, because these two logs are usually recorded and they can be recorded both into open and cased holes.

This method gives us the possibility to obtain Lorenz Coefficient for the fields where samples do not exist or their number is reduced and we can not make a statistical calculus. These fields are especially mature fields where enhanced recovery processing or drilling horizontal wells are necessary to be applied and have to know the reservoir heterogeneity.

In the application presented in this paper, the value of Lorenz Coefficient calculated with equations (5) and (18) for the field is 0.478 (see table 1) and from the samples calculated with equations (4) and (5) is 0.370.

The difference between the two values from the equations (5), (18), and equations (4) (5) are 0.108. It is very difficult to say what value is exactly. The value obtain from measurement on samples are one a hand, a few and can not be representative and the other hand, the determinations can have errors. The value obtained from the logs, was determined on a big number of property values and can be more representative.

In conclusion we can consider that the equations (5), (18) can be used with great reliance.

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