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AIR TO LIQUID PERMEABILITY CONVERSION FORMULA PROVES EFFECTIVE FOR NIGER DELTA SANDSTONE RESERVOIR OFFSHORE NIGERIA

Augustine Okechukwu Chukwuemeka[1], Goodluck Amede[2], Mustapha Abdulsalam[2], Kazeem Alani Odunlami[2], Eganoba Shada Oyintinloy[2]*

[1] *Akwa Ibom State University Ikot Akpaden*
[2] *Institute of Oil, Gas and Energy, Kuban State Technological University Krasnodar, Russia*

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Abstract

As the petroleum industry strives to make more accurate estimation of in-place amount of reservoir fluid and predict their recoverability/ recovery ratio by use of computer simulation, liquid permeability data is of non-negligible importance for both sandstone and carbonate reservoir. The liquid permeability of a reservoir rock could be determined either by a direct core sample analysis in the laboratory or estimated by using a correlation, which connects air permeability to liquid permeability. Given that the industry already has a large amount of air permeability data, the correlation approach for determining liquid permeability is less capital intensive since it eliminates the need for expensive laboratory procedures that would otherwise have been involved in determining this value. In this work, we tested the validity of two previously proposed conversion formulae (equation 2 and 4) on a set data acquired from the Niger Delta sandstone reservoir in Nigeria and some carbonate reservoirs in the Middle East. While equation 2 proves very effective in converting the Niger Delta sandstone reservoir's air permeability data to liquid permeability at various intervals and varied pressure with a maximum absolute average error of 9.65%, equation 4 is ineffective in doing same, giving a minimum average error of 153.7%. Applied to data from carbonate reservoir, equation 2 also became ineffective. In this case, giving a minimum average error value of 69.2%. The results are further indication that carbonate and sandstone reservoirs differ significantly in their nature and thus properties; and therefore, behave differently when subjected to same conditions; in this case conversion formulae of air permeability to liquid permeability.

***Keywords**: Air permeability; Liquid permeability; core samples; carbonate reservoir; sandstone reservoir; Niger Delta.*

1. Introduction

The most common types of reservoir rocks are the sedimentary rocks. Sedimentary rocks are made up of sediments that have been compacted closely by natural forces. Reservoir sedimentary rocks are classified into sandstones and carbonates (limestone and dolomite). There are different types of sandstone reservoir rocks such as river sandstones, dune sandstones, shoreline sandstones, and delta sandstones. But of primary importance is the delta sandstone which is the type of sandstone located in the Niger delta region of Nigeria, where rock samples were studied and data acquired for this article.

The Niger delta sandstone, which is one of the largest oils producing delta sandstones in the world with an approximate 34.5 billion barrels of recoverable oil, and 94 trillion feet^3 of natural gas [1], was formed by a periodic deposition of sediments from rivers (Niger and Benue) flowing into the Atlantic Ocean and wave erosion. The fact that wave erosion shapes the delta makes the Niger delta a destructive type. The river being rich in organic sediments flows into the Atlantic Ocean and deposits its organic content at the bottom of the ocean which gets covered in mud and over time forms black shale which is a source rock where oil and gas can be formed. The formed oil and gas over time find their ways to the overlying sedimentary rocks and get trapped by the rock cap.

In the determination of the productivity and economic viability of reservoir rock, one of the major characteristics taken into consideration is its ability to allow fluid transmission through it: a phenomenon termed permeability, which is represented by the letter "K." Without sufficient formation permeability, oil and gas production, secondary and tertiary recovery, and carbon sequestration are impossible [3]. To determine the value of this property, core samples are taken to the laboratory for analysis.

For an oil reservoir, of course, it is most desirable that the permeability of the reservoir to oil (K_{oil}) is deter-mined to a high degree of accuracy. However, in some cases, a correlation approach becomes an important, if not the only method for estimating K_{oil} especially during simulation or modeling of the reservoir rock.

If a reliable formula is established for converting air to liquid permeability, the need for expensive experimental procedures for determining liquid permeability during core sample testing will not be necessary. This also will be of great value during side tracking for enhanced recovery in mature fields where liquid permeability data may not be available, saving time on reservoir re-evaluation before side-tracking. This approach cuts down on drilling time and resources, which is of great economic importance to drilling contractors.

Up to this point several attempts have been made in converting between gas and liquid permeability. In this article, core sample data from a sandstone reservoir located in Delta State of the Niger delta region mentioned above shall be used to test the validity of conversion formulae put forward in previous articles.

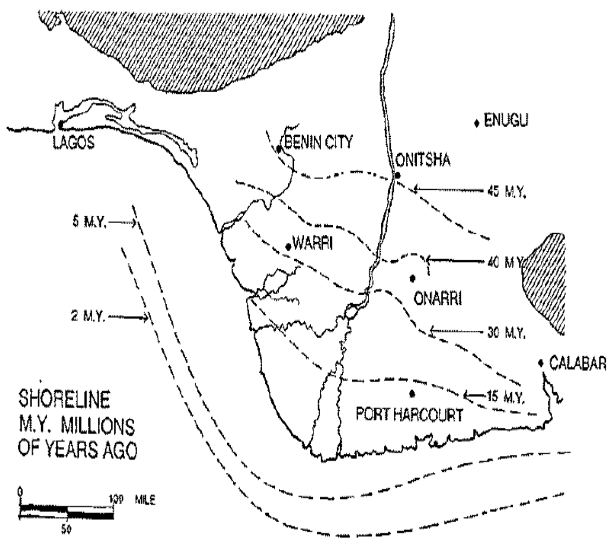

Fig.1. Present day and ancient shorelines of the Niger River Delta, Nigeria (*modified from Burke, 1972*) [2]

2. Overview of permeability and air to liquid permeabiity conversion formulae

With the discovery of crude oil and the increased use of its products as a primary source of energy for humanity came the need for detailed understanding of reservoir petrophysical properties such as porosity, permeability, relative permeability, capillarity, and saturation. Methods of measuring these properties in the laboratory have been developed with yet a constant attempt at improving on existing methods for enhanced accuracy.

The fundamental law of fluid motion in porous media is Darcy's law. The mathematical expression developed by Darcy in 1956 states that the velocity of a homogeneous fluid in a porous medium is proportional to the pressure gradient and inversely proportional to the fluid viscosity. For a horizontal linear system, this relationship is:

$$v = \frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dx} \quad (1)$$

where: v is the apparent velocity in centimeters per second and is equal to q/A, where q is the volumetric flow rate in cubic centimeters per second, and A is the total cross-sectional area of the rock in square centimeters.

In other words, A includes the area of the rock material as well as the area of the pore channels. The fluid viscosity, μ, is expressed in centipoise units, and the pressure gradient, dp/dx, is in atmospheres per centimeter, taken in the same direction as v and q. The proportionality constant, k, is the permeability of the rock expressed in Darcy units [4].

With increasing demand on the industry and a need to cut costs of data acquisition and improve reservoir fluid production efficiency, attempts have been made in the past to estimate permeability from porosity data. However, it has been proven that a direct proportionality does not always exist between porosity and permeability since a sample may have large pores which are either totally unconnected or have little interconnectivity thereby giving rise to low permeability.

By definition, any fluid can be used to measure absolute permeability. In practice, absolute permeability is measured by flowing air through a core sample that has been completely dried [5]. However, in laboratory conditions, replacing air with brine or oil in the experiment we get permeability to brine and permeability to oil respectively.

These forms of permeability vary both in the degree of difficulty and cost of measurement as well as their values; permeability to air, being the least capital intensive. In as much as permeability to air does give an idea of the reservoir rocks' permeability to liquid, depending totally on its value fails to provide a perfect prediction of reservoir fluid productivity especially if the liquid is to be produced from the reservoir. This is partly due to the fact that adhesion forces between air and reservoir vary significantly to that between reservoir fluid and the reservoir rock. At low rates, air permeability will be higher than brine permeability. This is because gas does not adhere to the pore walls as the liquid does, and the slippage of gases along the pore walls gives rise to an apparent dependence of permeability on pressure. This is called the Klinkenberg effect, and it is especially important in low-permeability rocks [6].

This, therefore, increases the need for a more accurate and cheaper method of either measuring or estimating the permeability of the reservoir to the liquid expected to be produced from it. In an attempt to solve this problem, a number of researchers have studied the possibility of deriving a formula which, when given the reservoir permeability to air, can estimate the reservoir's permeability to liquid with great accuracy.

In his study Macary [7], working on sandstone reservoirs from different parts of the world, applied equation (2) for estimating permeability to brine and equation (3) for permeability to oil of a sandstone reservoir from permeability to air with an average error value of 19.21%.

$$\text{Log } K_{brine}=1.0488 \text{ Log } K_{air} - 0.7222;\ R^2 = 0.85; \quad (2)$$

$$\text{Log } K_{oil} = 1.0913 \text{ Log } K_{air} - 0.4946;\ R^2 = 0.95; \quad (3)$$

Another researcher Al-Sudani *et al.* [8], in his study on reservoir samples, from different oil fields around the Middle East, applied equation (4).

$$K_l = A \cdot k_a \cdot \varphi^{0.09} \quad (4)$$

where Ka and K_l are the air and liquid permeabilities respectively in millidarcy (md). (A = 0.73) for air permeability values less than unity, and (A = 1.002) for air permeability values greater than unity [8]. With this formula, the average absolute error was 4.16%. Further investigation into the nature of the reservoirs reveals that they are mostly carbonate reservoirs. This, however, was not clearly stated in work; giving an impression of general applicability.

As expected, the above formulae vary greatly given that carbonate and sandstone reservoirs differ in their composition and structure: from their chemical components to their physical characteristics. Table 1 below summarizes the differences between these reservoir rock types.

The two major differences between carbonate and sandstone reservoirs can be summarized as follows:

1. the site of sediment production,
2. the greater chemical activity of carbonate minerals [9-10].

Carbonate reservoirs which hold more than 60% of the world's oil are of immeasurable importance to the oil and gas industry and studying their productivity and permeability should take their porosity into account. This is because unlike sandstone reservoirs, carbonate reservoirs have varied forms of porosity. These include:

1. connected porosity existing between carbonate grains
2. vugs which are unconnected pores resulting from dissolution of calcite by water during diagenesis
3. fracture porosity which is caused by stress after deposition [11].

Table 1. Comparison of carbonate and sandstone reservoirs

Reservoir type	Main mineral composition	Site of sediment deposition	Wettability	Effect of diagenesis	Chemical activity of mineral
Carbonate	Calcite ($CaCO_3$)	authochthonous	Oil wet/mixed wet	Reduces porosity	Highly active
Sandstone	Sand (SiO_2)	allochthonous	Water wet	Hardly noticeable	Comparatively inactive

3. Data acquisition and methodology

The set of data used for calculations in this article includes air permeability, porosity, depth, and pressure. In acquiring data for this article, we examined core samples (Figures 3.-5.) from three different wells in the Niger Delta region of Nigeria, namely: Freeman1, Freeman 2ST1, and Freeman 3ST1. The samples were taken at different depths, and air permeability and porosity measurements were carried out at different pressures.

As to Freeman1 well the core samples were taken from the interval 8100ft to 8111ft and measurements were carried out at 1000psi. The resulting air permeability data fluctuate from 8160md to 4590md. At 3000psi from interval 8100ft to 8111ft measured air permeability data fluctuate between 7200md to 3280md. At 4500psi from interval 8100ft to 8111ft measured air permeability data fluctuate between 6640md to 2480md.

As to Freeman-2ST1 well the core samples were taken from the interval 9351ft to 9363ft and measurements were carried out at 1000psi. The resulting air permeability data fluctuate from 6280md to 1540md. At 3000psi from interval 9351ft to 9363ft measured air permeability data fluctuate between 4010md to 955md. At 4500psi from interval 9351ft to 9363ft measured air permeability data fluctuate between 3640md to 741md.

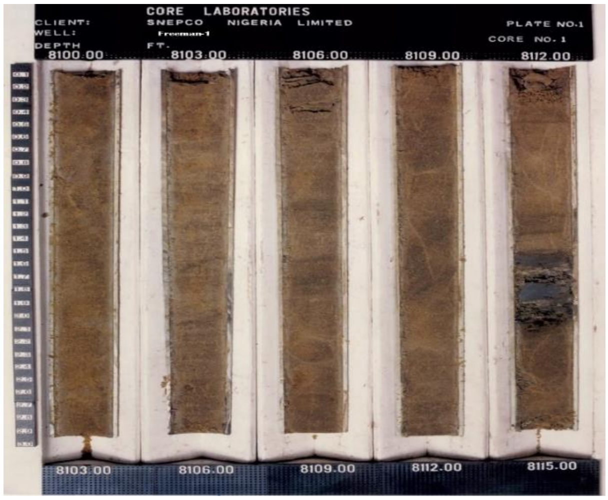

Fig.3. Core sample from FREEMAN 1 (8100-8111 ft).

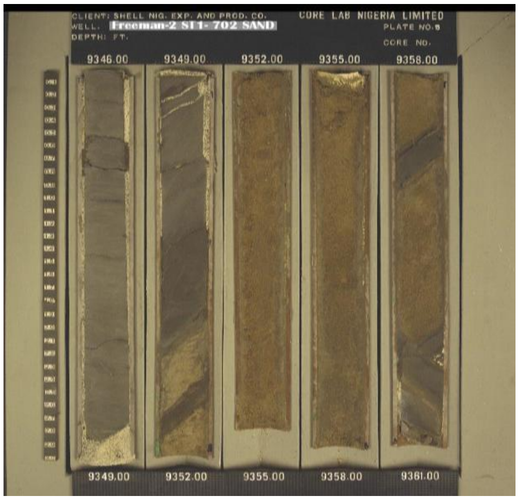

Fig.4. Core sample from FREEMAN 2 ST1 (9346-9361 ft)

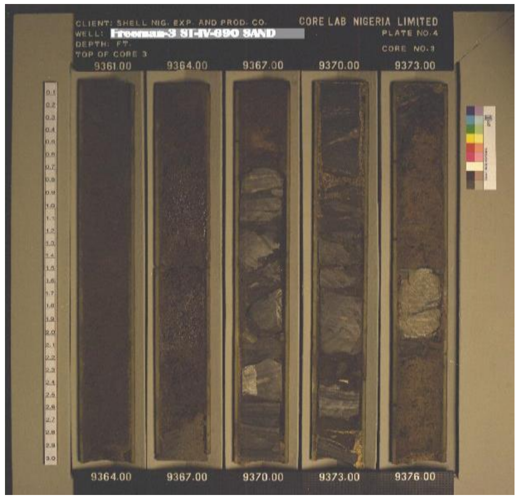

Fig.5. Core sample from FREEMAN 3ST1 (9361-9376 ft).

In addition to this, core sample data were taken from areas within the Middle East as stated by Al-Sudani *et al.* [7].

As to Freeman-3ST1 well the core samples were taken from the interval 9363ft to 9557ft and measurements were carried out at 1000psi. The resulting air permeability data fluctuate from 9610md to 321md. At 3000psi from interval 9363ft to 9557ft measured air permeability data fluctuate between 5610md to 226md. At 4500psi from interval 9363ft to 9557ft measured air permeability data fluctuate between 4760md to 139md.

We applied the conversion formulae by Macary [7] (equation 2) and (equation 4) by Al-Sudani *et al.* [8] to our data.

4. Results and discussion

Refer to appendix for tables and graphs.

The tables 2 to 10 show the result of applying equation 2 to core sample data from wells in the sandstone reservoir of the Niger delta region of Nigeria. Tables 11 to 13 show the results of applying equation 4 to the same reservoir, while table 14 and 15 show the results of applying equation 2 to data from carbonate reservoirs from locations within the Middle East.

The maximum average absolute percentage error for a chosen interval on the sandstone reservoirs from table 2 to 10 is 9.65%. This is obtained from Freeman 2ST1 at a pressure of 3000 psi. On the other hand, tables 11 to 13 show a minimum average absolute error of 153.7%; a very significant deviation reflecting the inapplicability of equation 4 to sandstone reservoirs. Tables 14 and 15 show a minimum average error of 69.2%.

The average absolute error observed when applying equation 2 to data from Freeman1 and freeman3st well decreases with an increase in the pressure of liquid permeability measurement from 1000psi to 4500psi. However, on applying equation 2 to data from Freeman2st1, the average absolute error increases with increasing pressure.

On each of the intervals examined under fixed pressure of measurement, the change in absolute error values does not follow a particular trend with increasing depth.

The above suggests that the accuracy of equation 2 for converting air to liquid permeability is affected by the depth from which the core sample was taken and the pressure at which laboratory liquid permeability data is conducted. The inconsistency in the pattern of their effects suggests the possibility of another factor (s) that affect the accuracy of the equation 2. The large error values encountered when equation 2 is applied to carbonate reservoirs suggest that the accuracy of the equation is affected by the chemical composition of the core sample.

In addition to the above, the large errors seen when equation 2 and equation 4 are applied to carbonate and sandstone reservoirs respectively underscores the difference between carbonates and sandstone reservoirs. None of the two equations can be universally applied to both sandstones and carbonate reservoirs. However, when applied independently to the sandstone reservoirs of Nigeria, equation 2 shows a high accuracy and extends its applicability beyond the areas on which it was first applied by Macary [7].

5. Limitations

While the data pool is not large enough to represent the entire reservoir structure of the Niger Delta region of Nigeria, by applying the formula at varying intervals and different pressure conditions, we have tried to accommodate varying reservoir conditions.

Bearing in mind that the main reservoir rock of the Niger Delta is the Agbada formation, it is reasonable to assume that the calculations fairly represent the applicability of this formula for converting air to liquid permeability in the Niger Delta. This work has calculated liquid permeability to brine and has made no attempt at calculating liquid permeability to oil. Though the formula for the later calculation is stated in work, laboratory data is not available to us, and we, therefore, cannot estimate errors.

6. Recommendations

To further solidify the veracity of this formula, more data from other sandstone reservoirs from around the world should be tested. In addition to this, further research should be carried out to understand the relationship between porosity and the accuracy of the formula and find the possible air permeability range for which the formula is most accurate. These recommendations are made on the following observations:

In Freeman1 well, the highest percentage error was 8.20% at a porosity of 32.5 and air permeability of 4160 milli Darcy at a pressure of 3000 psi while the lowest was -5.117% at a pressure of 3000 psi, permeability of 4760 mD and porosity of 31.1 such trends are visible throughout the entire tables.

With shale content likely not playing a significant role in the accuracy of the formula because of brine, the chances are that the formula has limitations to either porosity, pressure or air permeability values. These factors may act independently or in combination to affect the accuracy of the formula.

7. Conclusions

1. Equation 2 which was initially proven to be effective in Nubia “C” reservoir extends its validity and consistency to sandstone reservoir of the Niger Delta region of Nigeria under varying pressure conditions and reservoir depths.
2. Application of equation 4 to sandstone reservoir of the Niger delta region of Nigeria, showed a considerably large error margin in comparison to its application in some Iraqi and Egyptian oil fields with predominantly carbonate reservoir rocks.
3. Application of equation 2 to data from the Iraqi and Egyptian oil fields proves to be ineffective for conversion of air permeability to liquid permeability.
4. The above observations suggest that due to the varying nature of sandstone and carbonate reservoirs, a formula developed for converting air permeability to liquid permeability in carbonate reservoirs cannot be applied effectively for the same conversion in sandstone reservoirs and vice-versa.
5. This method of estimating liquid permeability from core sample air permeability data which has been proven effective in a good number of oil fields goes a long way to save cost and time. This is valuable for the development of new oil fields and revitalization of mature fields.

APPENDIX

APPLICATION OF EQUATION 2 TO SANDSTONE RESERVOIRS

(where* Log Kbrine *is the calculated brine-permeability using equation 2)*

Table 2. Application of equation 2 to FREEMAN-1 at a depth range of (8100.15ft - 8111.05 ft) and pressure of 1000psi

well	depth	por_1000	ka_1000	kb_1000	Logkb_1000	Log Kbrine	error %	absolute error
Freeman-1	8100.15	33.8	4590	1166	3.06669855	3.118309145	-1.68294	1.68293666
Freeman-1	8101.00	34.6	4900	2360	3.372912	3.148077649	6.665883	6.665882598
Freeman-1	8102.00	34.2	7460	3185	3.50310944	3.339528482	4.669593	4.669593039
Freeman-1	8103.60	34.3	5990	1930	3.28555731	3.239565251	1.399825	1.399825155
Freeman-1	8104.90	34.3	6340	2529	3.40294883	3.265431214	4.041131	4.041130871
Freeman-1	8106.20	34.4	4620	1872	3.27230584	3.121276504	4.61538	4.615379724
Freeman-1	8106.95	34.3	5520	2891	3.46104809	3.202345705	7.474683	7.474683393
Freeman-1	8107.95	33.5	7690	1970	3.29446623	3.353359545	-1.78764	1.787643733
Freeman-1	8109.55	33.0	5920	1250	3.09691001	3.234211006	-4.43348	4.433483454
Freeman-1	8110.30	34.3	5460	1879	3.27392678	3.197367644	2.33845	2.338449867
Freeman-1	8111.05	33.1	8160	3678	3.56561172	3.380380639	5.194931	5.194931493
				average error	2.590528	4.027630908		

Table 3. Application of equation 2 to FREEMAN-1 at a depth range of (8100.15ft - 8111.05 ft) and pressure of 3000psi

well	depth	por_3000	ka_3000	kb_3000	Log kb_3000	Log Kbrine	error %	absolute error
Freeman-1	8100.15	32.0	3280	852	2.93043959	2.96524849	-1.18784	1.187838595
Freeman-1	8101.00	32.8	3690	1820	3.26007139	3.01889725	7.397818	7.397817608
Freeman-1	8102.00	32.0	5250	2083	3.31868927	3.17950308	4.194011	4.194010985
Freeman-1	8103.60	33.1	4250	1460	3.16435286	3.08325431	2.562879	2.562879351
Freeman-1	8104.90	31.8	4590	1659	3.21984639	3.11830914	3.153481	3.15348092
Freeman-1	8106.20	32.7	3470	1248	3.09621459	2.99089755	3.401477	3.401477168
Freeman-1	8106.95	32.5	4160	2230	3.34830486	3.07350509	8.207131	8.207131343
Freeman-1	8107.95	32.0	5620	1547	3.18949031	3.21052345	-0.65945	0.65945126
Freeman-1	8109.55	31.1	4760	960	2.98227123	3.13487417	-5.117	5.117004023
Freeman-1	8110.30	32.0	4560	1600	3.20411998	3.11532233	2.771359	2.77135863
Freeman-1	8111.05	31.8	7200	2705	3.43216727	3.32337032	3.16992	3.169919723
					average error	2.535798	3.802033601	

Table 4. Application of equation 2 to FREEMAN-1 at a depth range of (8100.15ft - 8111.05 ft) and pressure of 4500psi

well	depth	por_4500	ka_4500	kb_4500	Log kb_4500	Log Kbrine	error %	absolute error
Freeman-1	8100.15	30.6	2560	586	2.7678976	2.852362076	-3.05157	3.051574564
Freeman-1	8101.00	30.7	2920	1250	3.09691	2.912293535	5.961312	5.961312329
Freeman-1	8102.00	30.5	4670	1859	3.2692794	3.126179544	4.377107	4.377106646
Freeman-1	8103.60	31.6	2480	1005	3.0021661	2.837900923	5.471554	5.471554056
Freeman-1	8104.90	30.5	3360	1094	3.0390173	2.976224634	2.066217	2.066216846
Freeman-1	8106.20	30.6	2730	963	2.9836263	2.881647384	3.417952	3.417951616
Freeman-1	8106.95	30.2	3220	1654	3.2185355	2.956839238	8.130911	8.130911297
Freeman-1	8107.95	31.2	4320	1204	3.0806265	3.090695354	-0.32684	0.326844776
Freeman-1	8109.55	29.0	3000	860	2.9344985	2.924604772	0.337151	0.337150605
Freeman-1	8110.30	29.9	2540	1021	3.0090257	2.848789602	5.325183	5.325183426
Freeman-1	8111.05	30.8	6640	2069	3.3157605	3.286489882	0.882772	0.882772115
					average error		2.962885	3.57714348

Table 5. Application of equation 2 to FREEMAN-2ST1 at a depth range of (9351.20ft – 9364.20 ft) and pressure of 1000psi

well	depth	por_1000	ka_1000	kb_1000	Log kb_1000	Log Kbrine	error %	absolute error
Freeman-2ST1	9351.20	36.9	1540	454	2.65705585	2.620871732	1.361813	1.361812579
Freeman-2ST1	9352.25	32.3	4560	3420	3.53402611	3.115322327	11.84778	11.84778399
Freeman-2ST1	9353.10	32.9	6260	5090	3.70671778	3.259647161	12.06109	12.06109145
Freeman-2ST1	9354.00	30.2	4780	2910	3.46389299	3.136783978	9.443393	9.443392508
Freeman-2ST1	9356.85	33.6	3460	2000	3.30103	2.989583012	9.434843	9.434842569
Freeman-2ST1	9357.55	35.2	3310	1800	3.25527251	2.9693956	8.781965	8.781965405
Freeman-2ST1	9358.15	32.2	2460	1220	3.08635983	2.83421274	8.169724	8.169724341
Freeman-2ST1	9359.45	32.9	2480	1310	3.1172713	2.837900923	8.962017	8.962016658
Freeman-2ST1	9361.55	31.8	3260	1640	3.21484385	2.962462619	7.850497	7.850497288
Freeman-2ST1	9362.30	32.9	4170	2560	3.40823997	3.074598694	9.789254	9.789254109
Freeman-2ST1	9363.50	32.1	2670	1820	3.26007139	2.871525011	11.91834	11.91833953
Freeman-2ST1	9364.20	31.6	3370	1920	3.28330123	2.97757824	9.311451	9.311451109
					average error		9.077681	9.077680962

Table 6. Application of equation 2 to FREEMAN-2ST1 at a depth range of (9351.20ft – 9364.20 ft) and pressure of 3000psi

well	depth	por_3000	ka_3000	kb_3000	Logkb_3000	Log Kbrine	error %	absolute error
Freeman-2ST1	9351.20	34.2	955	379	2.57863921	2.40322754	6.80249	6.802489979
Freeman-2ST1	9352.25	31.1	3400	2100	3.32221929	2.98161509	10.25231	10.25230957
Freeman-2ST1	9353.10	29.9	3380	2380	3.37657696	2.97892784	11.77669	11.77669358
Freeman-2ST1	9354.00	29.4	4010	1310	3.1172713	3.05677782	1.940591	1.940590725
Freeman-2ST1	9356.85	31.8	2320	1380	3.13987909	2.8075238	10.58497	10.58497091
Freeman-2ST1	9357.55	32.4	2320	1060	3.02530587	2.8075238	7.198679	7.198679288
Freeman-2ST1	9358.15	30.1	1870	1120	3.04921802	2.70930748	11.14747	11.14746611
Freeman-2ST1	9359.45	30.2	1310	811	2.90902085	2.54719413	12.43809	12.438093
Freeman-2ST1	9361.55	30.4	2250	1330	3.12385164	2.79356902	10.57293	10.572929
Freeman-2ST1	9362.30	30.4	3040	1810	3.25767857	2.93063781	10.03907	10.03907393
Freeman-2ST1	9363.50	29.7	1840	1160	3.06445799	2.70194093	11.82973	11.82972838
Freeman-2ST1	9364.20	30.2	2420	1530	3.18469143	2.82674556	11.23958	11.23957792
					average error		9.651884	9.651883532

Table 7. Application of equation 2 to FREEMAN-2ST1 at a depth range of (9351.20ft – 9364.20 ft) and pressure of 4500psi

well	depth	por_4500	ka_4500	kb_4500	Log kb_4500	Log Kbrine	error %	absolute error
Freeman-2ST1	9351.20	32.0	741	353	2.5477747	2.287665337	10.20928	10.20927668
Freeman-2ST1	9352.25	30.8	3090	1610	3.2068259	2.938068453	8.380793	8.380792509
Freeman-2ST1	9353.10	28.6	2920	1610	3.2068259	2.912293535	9.184544	9.184544245
Freeman-2ST1	9354.00	28.6	3640	918	2.9628427	3.012683131	-1.68218	1.682183475
Freeman-2ST1	9356.85	30.8	1920	1120	3.049218	2.721326329	10.7533	10.75330434
Freeman-2ST1	9357.55	31.6	2070	901	2.9547248	2.755589698	6.739548	6.739547902
Freeman-2ST1	9358.15	29.1	1640	1070	3.0293838	2.649528228	12.53904	12.5390369
Freeman-2ST1	9359.45	29.0	960	639	2.8055009	2.405606069	14.25395	14.25395354
Freeman-2ST1	9361.55	29.8	2070	1220	3.0863598	2.755589698	10.71716	10.71716036
Freeman-2ST1	9362.30	29.6	2740	1550	3.1903317	2.88331279	9.623417	9.623416526
Freeman-2ST1	9363.50	28.3	1540	928	2.967548	2.620871732	11.68225	11.68224564
Freeman-2ST1	9364.20	28.8	2040	1350	3.1303338	2.74894012	12.1838	12.18380138
					average error		9.548741	9.829105293

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Table 8. Application of equation 2 to FREEMAN-3ST1 at a depth range of (9363.65ft – 9557.30ft) and pressure of 1000psi

well	depth	por_1000	ka_1000	kb_1000	Log kb_1000	Log Kbrine	error %	absolute error
Freeman-3ST1	9363.65	28.1	321	39	1.59106461	1.9066224	-19.8331	19.8331274
Freeman-3ST1	9367.50	30.0	2040	811	2.90902085	2.7489401	5.50290	5.50290777
Freeman-3ST1	9373.50	33.3	9610	1500	3.17609126	3.4548802	-8.77774	8.77773990
Freeman-3ST1	9374.25	31.6	3440	1670	3.22271647	2.9869424	7.31600	7.31600122
Freeman-3ST1	9547.65	33.4	2540	1020	3.00860017	2.8487896	5.31179	5.31179155
Freeman-3ST1	9549.20	30.8	3180	2150	3.33243846	2.9511455	11.4418	11.4418586
Freeman-3ST1	9550.20	32.5	3580	1850	3.26717173	3.0051125	8.02098	8.02098058
Freeman-3ST1	9550.60	30.9	3100	684	2.8350561	2.9395401	-3.68543	3.68543122
Freeman-3ST1	9554.40	33.0	4040	2220	3.34635297	3.0601727	8.55200	8.55200276
Freeman-3ST1	9555.20	25.6	3580	2380	3.37657696	3.0051125	11.0012	11.0012134
Freeman-3ST1	9556.20	32.3	4400	2140	3.33041377	3.0990531	6.94690	6.94690275
Freeman-3ST1	9557.30	32.4	5520	2770	3.44247977	3.2023457	6.97561	6.97561294
					average error		3.23108	8.61379751

Table 9. Application of equation 2 to FREEMAN-3ST1 at a depth range of (9363.65ft – 9557.30ft) and pressure of 3000psi

Freeman-3ST1	9363.65	26.2	226	29	1.462398	1.7467889	-19.4469	19.44689021
Freeman-3ST1	9367.50	27.8	1460	541	2.73319727	2.5965732	4.99868	4.998687497
Freeman-3ST1	9373.50	29.8	5610	928	2.96754798	3.2097122	-8.16042	8.160416432
Freeman-3ST1	9374.25	29.6	2480	861	2.93500315	2.8379009	3.30842	3.308419909
Freeman-3ST1	9547.65	32.5	2290	770	2.88649073	2.8015954	2.94112	2.941123994
Freeman-3ST1	9549.20	30.1	2650	1390	3.1430148	2.8681002	8.74684	8.746841652
Freeman-3ST1	9550.20	30.3	3100	1210	3.08278537	2.9395401	4.64661	4.646616894
Freeman-3ST1	9550.60	30.0	2580	570	2.75587486	2.8559067	-3.62977	3.629769027
Freeman-3ST1	9554.40	31.9	3530	1750	3.24303805	2.9987061	7.53404	7.534044745
Freeman-3ST1	9555.20	24.4	3100	1490	3.17318627	2.9395401	7.36313	7.36313926
Freeman-3ST1	9556.20	31.8	4210	2100	3.32221929	3.0789470	7.32258	7.322582016
Freeman-3ST1	9557.30	31.9	5100	2240	3.35024802	3.1662996	5.49059	5.490591044
					average error		1.75958	6.965760223

Table 10. Application of equation 2 to FREEMAN-3ST1 at a depth range of (9363.65ft – 9557.30ft) and pressure of 4500psi

well	depth	por_4500	ka_4500	kb_4500	Log kb_4500	Log Kbrine	error %	absolute error
Freeman-3ST1	9363.65	23.5	139	25	1.39794	1.52539392	-9.11727	9.11726633
Freeman-3ST1	9367.50	25.1	637	246	2.3909351	2.21878143	7.20026	7.20026528
Freeman-3ST1	9373.50	29.0	4760	750	2.8750613	3.13487417	-9.03678	9.03677817
Freeman-3ST1	9374.25	27.0	1520	636	2.8034571	2.61491755	6.72525	6.72525217
Freeman-3ST1	9547.65	31.5	1840	520	2.7160033	2.70194093	0.51776	0.51776117
Freeman-3ST1	9549.20	29.2	2610	1020	3.0086002	2.86117256	4.90020	4.90020605
Freeman-3ST1	9550.20	29.8	2830	920	2.9637878	2.89803361	2.21858	2.21858707
Freeman-3ST1	9550.60	28.6	2270	315	2.4983106	2.79759999	-11.9797	11.9796702
Freeman-3ST1	9554.40	30.5	2930	1100	3.0413927	2.91385076	4.19353	4.19353691
Freeman-3ST1	9555.20	24.3	2830	1090	3.0374265	2.89803361	4.58917	4.58917720
Freeman-3ST1	9556.20	30.9	3820	1050	3.0211893	3.03466805	-0.44614	0.44614072
Freeman-3ST1	9557.30	30.2	4090	1240	3.0934217	3.06577540	0.89371	0.89371196
					average error		0.05488	5.15152944

APPLICATION OF EQUATION 4 TO SANDSTONE RESERVOIRS

[where* K_l *is liquid (brine) permeability]*

Table 11. Application of equation 4 to FREEMAN-1 at a depth range of (8100.15ft – 8111.05ft) and pressure of 1000psi.

well	depth	por_1000	ka_1000	kb_1000	K_l	error %	absolute error
Freeman-1	8100.15	33.8	4590	1166	6313.684995	-441.482	441.4824181
Freeman-1	8101.00	34.6	4900	2360	6754.304728	-186.199	186.1993529
Freeman-1	8102.00	34.2	7460	3185	10272.32848	-222.522	222.5220874
Freeman-1	8103.60	34.3	5990	1930	8250.324201	-327.478	327.4779379
Freeman-1	8104.90	34.3	6340	2529	8732.396567	-245.29	245.2904929
Freeman-1	8106.20	34.4	4620	1872	6365.022701	-240.012	240.0118964
Freeman-1	8106.95	34.3	5520	2891	7602.969881	-162.988	162.9875435
Freeman-1	8107.95	33.5	7690	1970	10569.34548	-436.515	436.5149991
Freeman-1	8109.55	33.0	5920	1250	8125.604554	-550.048	550.0483643
Freeman-1	8110.30	34.3	5460	1879	7520.328904	-300.23	300.2303834
Freeman-1	8111.05	33.1	8160	3678	11203.20801	-204.601	204.6005441
					average error	-301.579	301.5787291

Table 12. Application of equation 4 to FREEMAN-2ST1 at a depth range of (9315.20ft – 9364.20ft) and pressure of 3000psi

well	depth	por_3000	ka_3000	kb_3000	K_l	error %	absolute error
Freeman-2ST1	9351.20	34.2	955	379	1315.023284	-246.972	246.9718428
Freeman-2ST1	9352.25	31.1	3400	2100	4642.184593	-121.056	121.0564092
Freeman-2ST1	9353.10	29.9	3380	2380	4598.273815	-93.2048	93.20478213
Freeman-2ST1	9354.00	29.4	4010	1310	5447.074985	-315.807	315.8072508
Freeman-2ST1	9356.85	31.8	2320	1380	3173.760475	-129.983	129.9826431
Freeman-2ST1	9357.55	32.4	2320	1060	3179.10416	-199.915	199.9154868
Freeman-2ST1	9358.15	30.1	1870	1120	2545.542267	-127.281	127.2805596
Freeman-2ST1	9359.45	30.2	1310	811	1783.77323	-119.947	119.9473774
Freeman-2ST1	9361.55	30.4	2250	1330	3065.103585	-130.459	130.4589162
Freeman-2ST1	9362.30	30.4	3040	1810	4141.903036	-128.834	128.8344219
Freeman-2ST1	9363.50	29.7	1840	1160	2501.690763	-115.663	115.6629968
Freeman-2ST1	9364.20	30.2	2420	1530	3295.361844	-115.383	115.383127
					average error	-153.709	153.7088178

Table 13. Application of equation 4 to FREEMAN-2ST1 at a depth range of (9315.20ft – 9364.20ft) and pressure of 4500psi

well	depth	por_3000	ka_4500	kb_4500	K_l	error %	absolute error
Freeman-2ST1	9351.20	34.2	741	353	1020.34791	-189.05	189.0503993
Freeman-2ST1	9352.25	31.1	3090	1610	4218.926586	-162.045	162.0451295
Freeman-2ST1	9353.10	29.9	2920	1610	3972.473236	-146.737	146.7374681
Freeman-2ST1	9354.00	29.4	3640	918	4944.477044	-438.614	438.6140571
Freeman-2ST1	9356.85	31.8	1920	1120	2626.560393	-134.514	134.5143208
Freeman-2ST1	9357.55	32.4	2070	901	2836.528281	-214.82	214.8200089
Freeman-2ST1	9358.15	30.1	1640	1070	2232.454181	-108.641	108.6405777
Freeman-2ST1	9359.45	30.2	960	639	1307.192596	-104.568	104.5684814
Freeman-2ST1	9361.55	30.4	2070	1220	2819.895298	-131.139	131.1389589
Freeman-2ST1	9362.30	30.4	2740	1550	3733.162605	-140.849	140.8492003
Freeman-2ST1	9363.50	29.7	1540	928	2093.806399	-125.626	125.6256896
Freeman-2ST1	9364.20	30.2	2040	1350	2777.908331	-105.771	105.7709875
					average error	-166.865	166.8646066

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Table 14. Application of equation 2 to data from carbonate reservoirs from locations within the Middle East

Measured K_{air} md	porosity	laboratory K_{liquid}. md	log K_{liquid}.	calculated K_{liquid}. Using equation 4.	calculated K_{liquid}. Using equation 2.	% error
6.9	0.23	5.2	0.716003344	5.12	1.437424114	72.35723
5.1	0.189	3.8	0.579783597	3.62	1.046886503	72.45036
158	0.226	142	2.152288344	147.49	38.34878005	72.99382
34	0.233	28	1.447158031	28.36	7.656232056	72.65631
23.7	0.247	20	1.301029996	19.34	5.243678607	73.78161
64.2	0.2	55	1.740362689	55.4	14.91223494	72.88685
6	0.283	4.5	0.653212514	4.47	1.24143799	72.41249
4.4	0.255	3.3	0.51851394	3.174	0.896712383	72.8269
5.6	0.242	4.2	0.62324929	4.09	1.154780928	72.50522
12.8	0.184	10	1	9.71	2.748158748	72.51841
25	0.188	21	1.322219295	19.99	5.545739698	73.59172
8.4	0.209	6.5	0.812913357	6.25	1.766786675	72.81867
					average error	72.81663

Table 15. Application of equation 2 to data from carbonate reservoirs from locations within the Middle East

Measured K_{air} md	porosity	laboratory K_{liquid}. md	log K_{liquid}.	calculated K_{liquid}. Using equation 4.	calculated K_{liquid}. Using equation 2.	% error
1275.9	0.189	1150.73	3.060973435	1100.5	342.9102677	70.20063
160	0.185	122.714	2.088894113	137.7	38.85805314	68.33446
408.43	0.153	337.728	2.528567068	345.6	103.8341411	69.2551
48.72	0.166	34.1326	1.533169371	41.5	11.16522283	67.28868
52.273	0.174	36.803	1.565883222	44.7	12.02068907	67.33775
1950.7	0.166	1821.34	3.260391026	1662.9	535.2439654	70.61263
2497.4	0.152	2379.81	3.376542285	2112.1	693.5623781	70.8564
1147	0.168	1027.14	3.011629642	978.9	306.6691664	70.14339
1169.2	0.21	1046.08	3.019564899	1018	312.8972747	70.08859
146.24	0.189	111.396	2.046869597	126.1	35.36074512	68.25672
391.34	0.176	322.014	2.507874754	335.4	99.28208466	69.16839
309.07	0.183	249.605	2.397253281	265.8	77.51247897	68.94594
					average error	69.20739

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To whom correspondence should be addressed: Augustine Okechukwu Chukwuemeka, Akwa Ibom State University Ikot Akpaden, Nigeria