SCIENTIFIC CONTRIBUTIONS OIL AND GAS
Vol. 42, Number 3, December 2019: 1 of 5
RESEARCH AND DEVELOPMENT CENTRE FOR OIL & GAS TECHNOLOGY LEMIGAS
Journal Homepage:http://www.journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

INTEGRATED INITIAL WATER SATURATION MODELLING

(*Pemodelan Saturasi Air Awal Terintegrasi*)

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First Registered on August, 23rd 2019; Received after Correction on October, 18th 2019
Publication Approval on: December 30th, 2019

ABSTRAK

Penelitian ini menyajikan sebuah pendekatan baru untuk memperkirakan nilai saturasi air awal. Nilai saturasi air awal tersebut ditentukan dengan mengintegrasikan data pengujian tekanan formasi (RFT), drill stem test (DST), well logging, dan pengukuran laboratorium (RCAL & SCAL). Metode ini menggunakan persamaan parametrik Brook-Corey untuk menghitung tekanan kapiler sintetik dan saturasi air awal sebagai fungsi kedalaman dan kelompok batuan. Kelompok batuan dan permeabilitas disebar secara vertikal dengan menggunakan interpretasi well log. Data DST dan pengujian tekanan formasi digunakan untuk mengontrol perhitungan saturasi awal tersebut. Proses perhitungan perlu mengiterasi konstanta Brook-Corey dengan menggunakan solver hingga memperoleh nilai yang menghasilkan nilai saturasi awal yang matched dengan semua data. Serangkaian langkah yang tepat dari metode ini disajikan dengan menggunakan data sintetik (karakteristik reservoir yang ideal). Studi kasus disediakan untuk menguji metode yang diusulkan ini. Produk dari studi ini (saturasi air awal) sangatlah penting ditentukan dengan teliti dimana data well log dapat berubah terhadap waktu (akibat aktifitas produksi) dan data pengukuran core sangatlah terbatas. Hasil studi kasus menunjukkan bahwa metode ini tidak dipengaruhi oleh kondisi mineralogi batuan ataupun kondisi reservoir lainnya. Pendekatan baru ini berhasil diintegrasikan dan matched dengan data lapangan dan data pengukuran laboratorium. Selain itu, metode ini dapat diterapkan di berbagai kondisi reservoir.

Kata Kunci: *saturasi air awal, tekanan kapiler, pengujian tekanan formasi, drill stem test, well logging, pengukuran core.*

ABSTRACT

This study presents a new approach to estimate initial water saturation. The initial water saturation is determined by integrating formation tester (RFT), drill stem test (DST), well logging, and laboratory measurement (RCAL & SCAL) data. This method utilizes Brook-Correy's parametrical equation to determine synthetic capillary pressure and initial water saturation as a function of depth and rock type. Rock type and permeability are distributed vertically by using well log interpretation. DST and formation tester data are used to control the initial water saturation calculation. The calculation needs to iterate Brook-Correy's constant by using solver until the results are matching with all data. The precise step of this method is presented by using synthetic data (ideal reservoir characteristic). Case studies are provided for testing the proposed method. The product of this study is essential where well log data could be changed by time (production activity) and core measurement data are very limited. The results of case studies demonstrate that the method is not affected by rock mineralogy or reservoir condition. This new approach is successfully integrated and matched with field and laboratory measurement data. Moreover, the method could be applied in any reservoir.

Keywords: initial water saturation, capillary pressure, formation tester, drill stem test, well logging, core measurement.

How to cite this article:

Wihdany, F.A., et al., 3, 2019, INTEGRATED INITIAL WATER SATURATION MODELLING, *Scientific Contributions Oil and Gas*, 42 (3) pp, 95-107. DOI: 10.29017/SCOG. 42.3.95-107.

INTRODUCTION

The determination of initial water saturation (S_{wi}) is essential to calculate initial hydrocarbon saturation (S_{hci} = 1-S_{wi}), which is imperative in calculating hydrocarbon volumes, both original oil in place (OOIP) and original gas in place (OGIP). However, initial water saturation (S_{wi}) determination is one of the most challenging of petrophysical calculations. Complexities arise because several independent approaches can be used to calculate water saturation, where those different approaches often lead to somewhat different Swi values. In addition, each of the approaches has weaknesses that may result in a significant difference in the (OOIP) or (OGIP) volumes.

Nowadays, there are two most common approaches that are used to determine S_{wi} value. The first one is S_w calculations from resistivity well logs by application of a model relating Sw to porosity, connate-water resistivity, and various rock electrical properties. The Second one is S_w calculations from saturation height function which is derived from laboratory capillary pressure (P_c- S_w) measurements. The capillary pressure relates to various rock and fluid properties and is converted to be height above the free-water level. However, those two approaches have a few weaknesses which may lead to the error in S_w values determination. Below are a few of weaknesses of S_w determination from well logs:

- The S_{wi} values from well log are too interpretive, meaning there is no single firm value that can be obtained. Instead, it depends on the engineer interpretation of what model is used. Because no uniquely satisfactory solution has been reached. When well logs data is obtained, the engineer chooses the “electrical network” model like Archie, Waxman-Smits-Thomas (WST), Simandoux, Indonesia, or other models to quantify the S_w values from those data. It means with the same method but a different model, the S_{wi} can have a different value.
- It is hard to know the initial water saturation from the formation because water saturation in the reservoir is changing by the time, due to water movement or migration throughout the subsurface. Since the log is recording a data in the present time, often, the water saturation value that is recorded is not the initial water saturation; instead, it is the current water saturation. This fact may lead to an error in an initial water saturation determination.
- The mineralogy effect that is not well represented in determining S_w values from well logs is causing an unreliable result. Diverse mineralogy will affect the resistivity differently, depends on the resistivity of each rock type. Despite some models taken into account of rock type in the reservoir, the error is still encountered because of the varies of rock type in the reservoir that cannot be calculated by the model.

Meanwhile, a few weaknesses S_w determinations from saturation height function or laboratory capillary pressure/saturation (P_c/S_w) measurements are:

- The difficulty of converting the result of S_{wi} value from lab condition to reservoir condition. Despite there is a rule of thumb to convert interfacial tension and contact angle from lab condition to reservoir condition, the rule is still too general. Meanwhile, in the real condition, each reservoir has unique characteristics, and that fact should be taken into account to represent the reservoir condition competently.
- The laboratory measurement data are available limitedly. With the limited data, a vast and vast area of the reservoir is represented with only available data, so that the S_w value will not well represent the real reservoir condition.

Because of all those weaknesses, this paper proposes a new method to determine the initial water saturation value that aims to give the best calculation by reconciles data from repeat formation tester, core laboratory data, drill stem test, and log data, which will be valuable in reserves estimation.

A. THEORY

Archie (1942), proposed an equation to estimate water saturation from a resistivity log. The Archie equation was the first empirical model built (1942) to estimate the water saturation in non-conductive matrix rocks (Archie, 1942). It usually works well with clean clastic sandstones and carbonate rocks. Typical parameters for the Archie equation for consolidated sandstones are a=0.81 (tortuosity), m=1.7 (cementation exponent), and n=2.0 (saturation exponent). For carbonates, typical parameters are a=1.0; m=n=2.0.

Simandoux (1963), developed a model for estimating water saturation in shaly sand formation. The model was a result based on laboratory studies performed on a physical reservoir model composed of artificial sand and clay in the laboratories of the Institute of French Petroleum (IFP). The most common cases happen on clastic shaly rocks with the important content of clay minerals (Simandoux, 1963) (Doveton, 2001) .

Waxman & Smits (1968), introduced a simple physical model that related the electrical conductivity of water-saturated shaly sand to the water conductivity and the cation-exchange capacity per unit pore volume of the rock. This model was extended to cases where both oil and water are present in the shaly sand (Waxman & Smith, 1968).

Clavier, etal., (1984), recommended a method which accounts for the resistivity behavior of clayey sands which was called with dual water equation. They defined water saturation by conductivity differences between water in rock pore and water-bound by clay (Clavier, et al., 1984).

Poupon & Leveaux (1970), presented an equation which included water resistivity, clay resistivity, porosity, and clay content in determining water saturation. They developed an equation which appropriates in cases where the ratio between clay resistivity and water resistivity (R_{clay}/R_w) was low and clay content was high (excess of 40% of clay). This equation is well known as an Indonesia model due to be developed by field observation in Indonesia rather than by laboratory experimental measurement support (Pouvon & Levaux, 1971) (Pouvon & Gaymard, 1970).

Water Saturation Height Function derived from Leverett's J-Function, calculated water saturation from capillary pressure which is transformed to a height above FWL. Water saturation height function from capillary pressure could represent initial water saturation and not influenced by time, because the samples are usually taken at the first well or exploration well (Leverett, 1940) (Adams, 2016).

Unfortunately, those methods had some weakness. The author tries to elaborate on the strength and the weakness of conventional water saturation estimation methods in Table 1. The proposed method in this study is also included to compare with the other methods.

II. METHODOLOGY

Figure 1 illustrates the integrated approach flow in this study Figure 1. The literature sourced from initial water saturation modelling research serves to be the basis to create this new method. The methodology did by integrating RFT, DST, logging, and laboratory data, as shown in Figure 2.

A. Rock Typing

Various quantitative rock-typing techniques are used in classifying rocks in the reservoir, Winland (Kolodzie Jr., 1980), HFU (Hydraulic Flow Unit) (Amaefule, et al., 1993), GHE (Global Hydraulic Unit) (Corbett & Potter, 2004), and PGS (Pore Geometry-Structure) (Permadi & Susilo, 2009) (Wibowo & Permadi, 2013). One of them could be used depending on reservoir type and condition. Once the rock typing has been done, rock type can be propagated into the well by determining rock type in each depth from logging data, with the equation that is obtained from the rock typing process. After that, permeability in each depth of logging data also can be obtained by creating the relationship between porosity and permeability for each rock type.

B. RFT Data Utilization

From RFT, fluid gradient and FWL depth can be obtained. Oil gradient, water gradient, and FWL will be used in calculating height above free water level from capillary pressure (Donaldson & Tiab, 2004).

$$\boldsymbol{P_c = 0.433\,(\rho_w - \rho_{nw})\,H} \tag{1}$$

If there is no RFT data, oil and water gradient can be calculated from density fluid obtained from PVT data.

C. Initial Water Saturation Calculation

Once rock typing is done, the next step is determining the S_{wi} value, which is the main point from this method. The calculation is adopted a Brook-Corey's equation S_{wi} value for each depth is obtained by using a parametric equation, which every rock type has a different equation. The parametric equation that is used is Brooks-Corey's equation which is adopted to describe saturation-dependent capillary pressure and relative permeability (Xu & Torres-Verdin, 2012).

$$\boldsymbol{P_c = P_c{}^0 \sqrt{\frac{\emptyset}{k}}(1 - S_N)^{e_p}} \tag{2}$$

P_c is capillary pressure in Psi, $P_c{}^0$ is a constant coefficient in psi.darcy$^{1/2}$, φ is porosity in fraction, *k* is absolute permeability in Darcy, e_p is pore-size distribution exponent, and S_N is normalized wetting phase saturation which is defined as:

$$\boldsymbol{S_N = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{nwr}}} \tag{3}$$

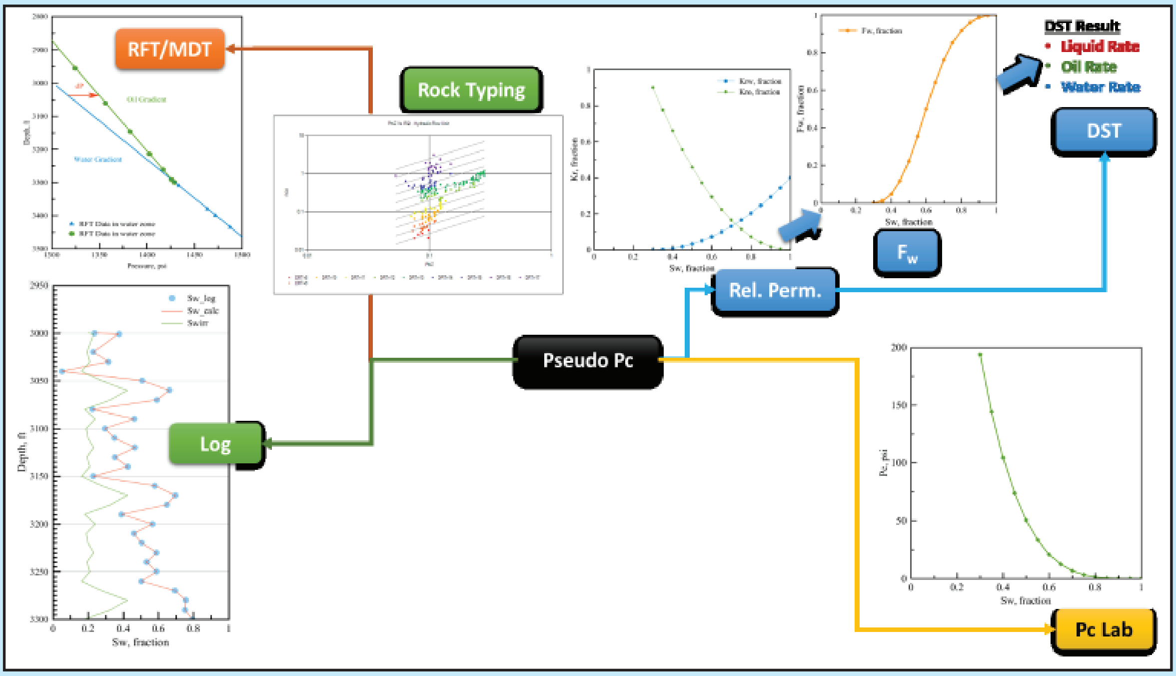

Figure 1
Calculation step of proposed method.

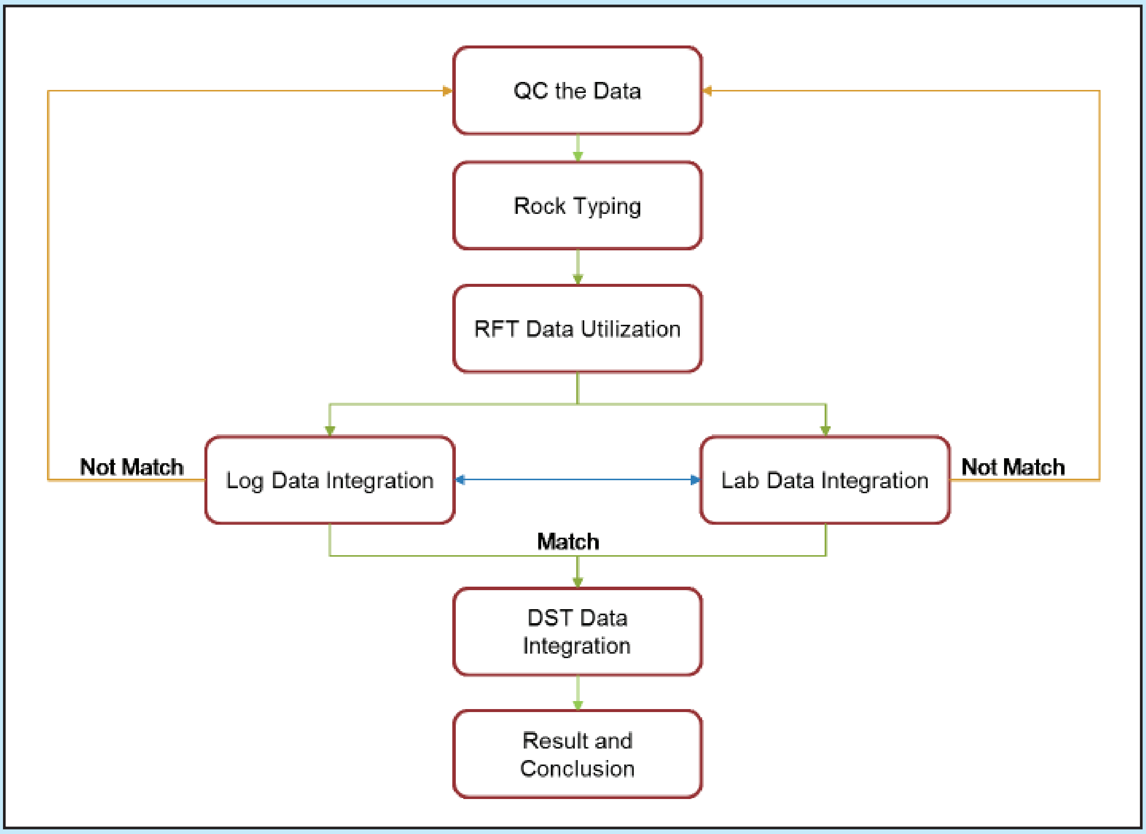

Figure 2
The workflow of the proposed method.

S_w is wetting-phase saturation, S_{wr} is residual wetting phase saturation, and S_{nwr} is non-wetting phase residual saturation (Xu & Torres-Verdin, 2012).

By combining equation (1), (2), and (3), the equation of S_w as a function of height above free water level can be obtained as follow:

$$S_w = S_{nwr} + (1 - S_{wr} - S_{nwr})\left(1 - \left(\frac{H(\rho_w - \rho_{nw})}{P_c^0}\sqrt{\frac{k}{\phi}}\right)^{\frac{1}{ep}}\right) \quad (4)$$

Based on Eq.1, it shows that the equation does not contain crucial parameters to be obtained and does not require interpretation. So that in this study prefer to use Brook-Corey equation approach compared to other existing equations such as Archie, Simandoux, Waxman-Smith, or Indonesian. However, the calculation still needs to be integrated with other data in order to produce an accurate calculation. Therefore, in this study, the authors developed an integrated initial water saturation calculation method that can be applied to various cases or reservoir conditions.

As mentioned above, the Eq.1 for every rock type will be different from one to another. The difference is underlying in the value of P_c^0 and ep, where these values are obtained by doing an iteration.

D. Well Log Data Integration

When the iteration process, there must be a value to set as a benchmark or objective function. The iteration process requires elaboration with a solver to get appropriate the value of Brook-Corey's variable. The iteration is done by synchronizing water saturation value that is obtained from SCAL and well logs. The iteration is done until the root mean square error (RMSE) is considered very small, or until the water saturation value that is obtained or calculated is satisfying. Then, S_w vs. depth calculated by this proposed method and resistivity log are plotted together to compare the result preciously.

E. Lab Data Integration

The integration and validation process being done by plotting P_c and S_w value from both SCAL data and calculated data. The first thing to do before making the comparison is that both data need to be plotted to iterate the interfacial tension value to convert the SCAL data from lab condition to reservoir condition. The iteration for interfacial facial tension is chosen overusing a general converting method because interfacial tension is hardly calculated. Usually, people use a general rule of interfacial tension to converting a fluid from lab to reservoir condition, which often results in an unreliable value. Therefore, the iteration is used in this paper. With this method, hopefully, the interfacial tension can be determined with better accuracy rather than the one from the general rule of thumb. If that single value of interfacial tension can make the P_c vs. S_w curve from all the sample from SCAL is the same or similar with calculated data, then it can be concluded that the S_w value from this method is matched with data from the lab.

F. DST Data Integration

From DST data, information about water cut, water flow rate, and oil flow rate can be found. Meanwhile, oil and water flow rates can also be determined if we have S_w data and by using the relative permeability curve from Special Core Analysis (SCAL) data processing. This allows us to compare fractional flow water (f_w) values between DST data and calculated data at DST test depth.

The steps used to validate the DST data include; The first is k_{rnw}-S_w curve from SCAL data using samples that have the same rock type and at a depth of perforation tested. Then check the DST interval. Then the average S_{wi} is calculated at this interval as the S_w value for the next flow rate calculation. After that, we can find out the relative permeability of the wetting phase and not by looking at the previously created S_w-curves using the average S_w value. After the relative permeability of the wetting and non-wetting fluid is known, and the viscosity of each phase is known, the water fraction can be calculated based on the following equation (Dake, 1977):

$$f_w = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{rnw}}{\mu_{nw}} + \frac{k_{rw}}{\mu_w}} = \frac{1}{1 + \frac{k_{rnw}\mu_w}{k_{rw}\mu_{nw}}} \quad (5)$$

Where fw is the fraction of flowing water, k_{rw} is the relative permeability of the wetting fluid, krnw is the relative permeability of the nonwetting fluid, μ_w is the viscosity of the wetting fluid and μ_{nw} is the viscosity of the non-wetting fluid, both in units of cp.

There are other methods for calculating water fractions from calculated data. This method considers the difference in residual S_{wi} and saturation of residual oil for different depths. Because, although the sample rock type is the same as the rock type obtained from the SCAL data, the sample obtained from the SCAL data does not originate from the same depth as the DST test depth, so that the residual water saturation is different from the water fraction. The following equation is used to calculate krw and krnw from this method (Xu & Torres-Verdin, 2012):

$$k_{rw} = K_{rw}^{0} S_{N}^{e_w} \tag{6}$$

and

$$k_{rnw} = k_{rnw}^{0} (1 - S_N)^{e_{nw}} \tag{7}$$

Where is the relative permeability of the wetting phase under residual conditions, and is the relative permeability of the non-wetting phase in residual conditions, ew is an experimental exponent, for k_{rw}'s equation, enw is an experimental exponent for k_{rnw}'s equation, and S_N and others are the same as in the previous equation.

Ew and enw are obtained by iterating the SCAL data. After obtaining the values ew and enw, krw, and krnw from the DST interval can be obtained, and furthermore, the water flow fraction can be calculated with the same equation as the previous method.

The ratio of oil rate and water rate calculated from and from DST data can be compared. When the ratio is equal or close, it can be concluded that the value of S_{wi} from the calculation is following S_{wi} from DST data.

G. Validation with Data Repeat Formation Tester (RFT)

After the saturation value of the logging depth is calculated and the parameter values P_{c0} and e_p of each rock group are generated, then the data can be used to calculate the P_c value per depth. Furthermore, the P_c value per depth can be validated with the P_c depth value generated from the repeat formation tester data.

III. RESULTS AND DISCUSSION

As discussed earlier, initial water saturation is a crucial parameter to calculate Original In-Place. Several common methods to estimate S_{wi} were discussed. However, how if the well log is already disturbed and changed by water influx?. Meanwhile, SCAL (Special Core Analysis Laboratory) data is very limited or cannot be used?.

Moreover, water saturation height function from capillary pressure needs to know precisely Free Water Level (FWL) depth. So, the proposed method in this study could cover those problems. Several cases will be provided to apply the proposed method.

A. Synthetic Data (Ideal Reservoir)

The synthetic data are prepared for the first test of the proposed method which has complete data such as, RFT, Well Log, SCAL, and RCAL. The ideal data is created for homogeny sandstone reservoir. RFT is available in oil and water zone, then FWL can be determined. The plot between pressures vs. depth from RFT data is provided in Figure 3, while capillary pressure curves from SCAL are presented in Figure 4.

Based on Figure 3, FWL is found at 3300 ft TVD. Oil gradient and water gradient are obtained 0.303 Psi/ft and 0.433 psi/ft. If the gradients are transformed to density, they become 0.7 gr/cc for oil density and 1 gr/cc for water density.

By those fluid density values, capillary pressures from laboratory measurement are plotted together with capillary pressure from RFT data. While capillary pressure is the pressure differences between the wetting phase and non-wetting phase, then capillary pressure could be obtained from RFT data. The plot is presented in Figure 5.

Based on RCAL and SCAL data, the plot between porosity and permeability, permeability and residual oil saturation, and permeability and irreducible water saturation could be created. All plots are presented in Figure 6.

Petrophysical properties (PHIE and SW) was already calculated and already validated, as shown in Figure 7. Then permeability, irreducible saturation, and residual oil/gas saturation could be estimated by using the equation obtained from Figure 6. The permeability result is displayed in Figure 8**.**

Height above FWL needs to be calculated. Depth of FWL is known from pressure vs. depth plot, then height above FWL is FWL depth minus reservoir depth (depth of log). By the depth of log, capillary pressure is calculated. Then, water saturation is calculated by using Eq.4 by using the first guess of $P_c^{\,0}$ and ep. Then, $P_c^{\,0}$ and ep are iterated by using solver until Root Mean Square Error is minimum (almost zero). The error is the difference between water saturation calculated (S_w calculated) and log interpretation. In this case, water saturation from log interpretation is considered a valid result. Therefore, the matching process is validated to S_w log. The S_w calculated result is plotted in Figure 9. The value of $P_c^{\,0}$ and ep which give matching S_w calculated are 20.3 Psi.Darcy$^{0.5}$ and 6.

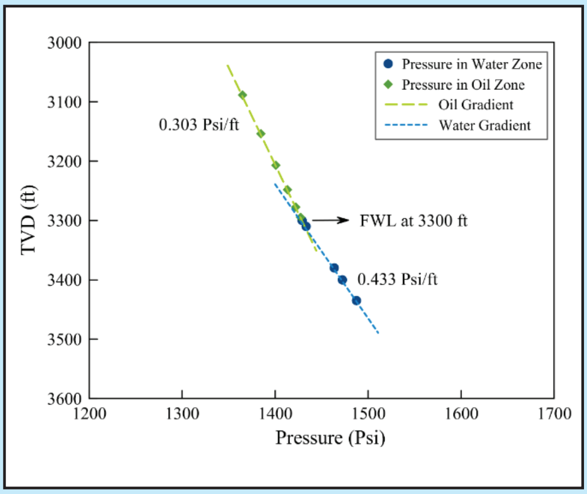

Figure 3
Pressure vs Depth from RFT (Repeat Formation Test).

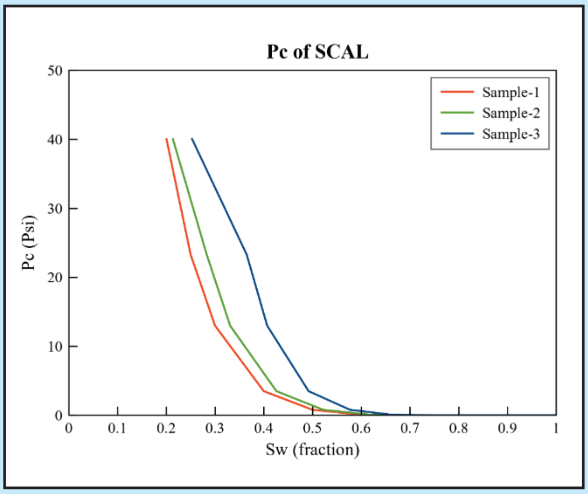

Figure 4
P_c from SCAL.

The value of P_c^0 and ep obtained are used to calculate P_c vs. S_w and compared to P_c vs. S_w from core measurement. The calculated P_c vs. Sw presents matching result to lab measurement as shown in Figure 10. The limitation of SCAL data could be covered by Sw calculated to distribute initial water saturation in well.

The matching result between S_w calculated and S_w log expose that well log still present initial condition (there has been no change due to water influx). If well log were recorded in a development well drilled after several years production and water influx was changed, it might not reflect initial water saturation and cannot be used to calculate hydrocarbon in-place.

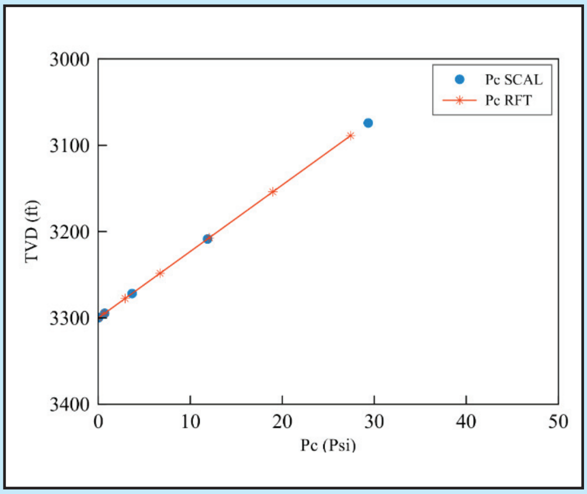

Figure 5
Capillary pressure of SCAL and RFP.

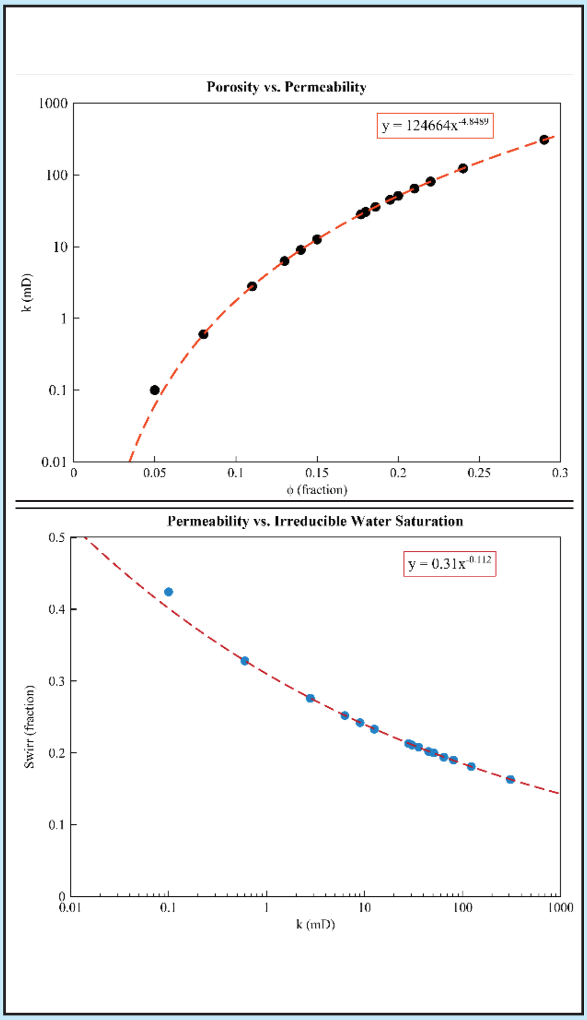

Figure 6
Data plot; a) Porosity vs Permeability, b) Permeability vs irreducible water saturation.

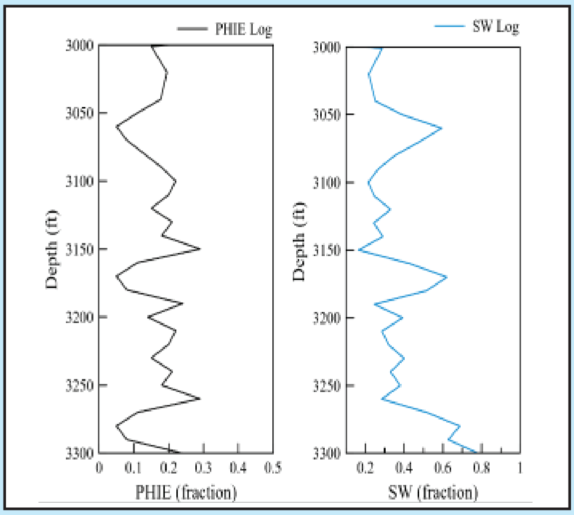

Figure 7
PHIE and SW from
petrophysical estimation result.

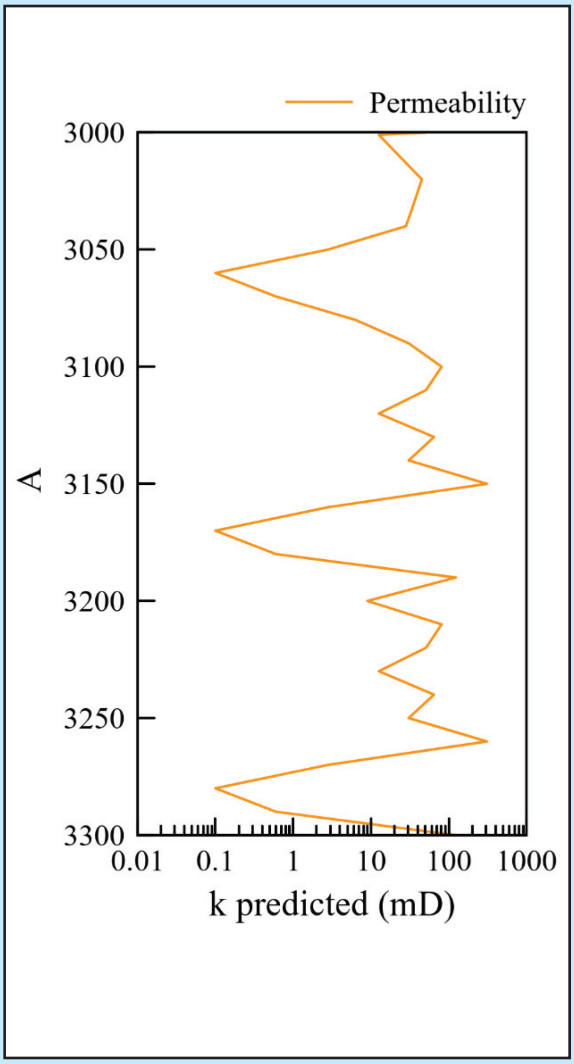

Figure 8
Permeability calculation result.

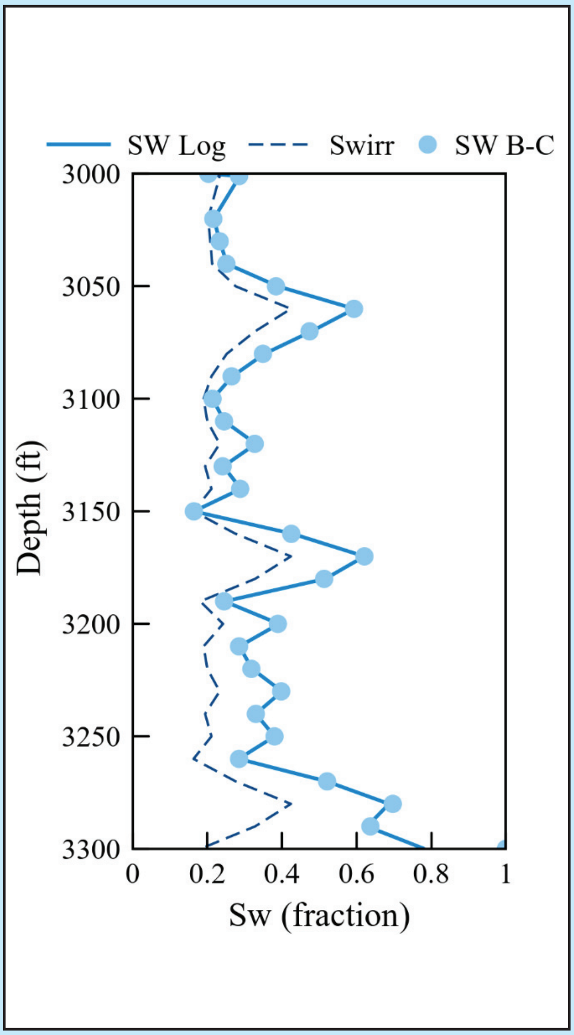

Figure 9
The plot between S_w calculation
from proposed method and S_w log.

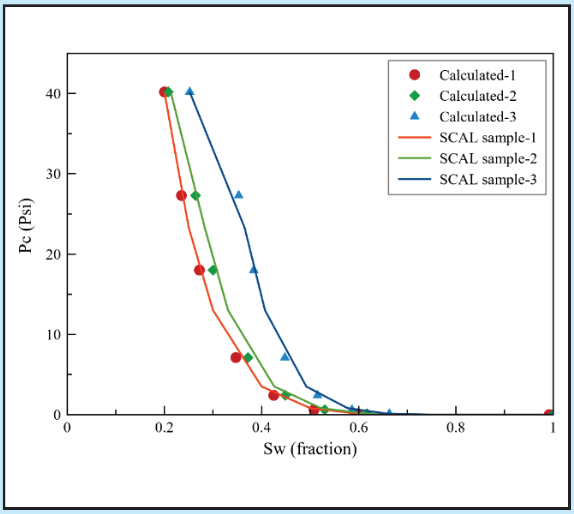

Figure 10
The plot between S_w calculation
from proposed method and S_w SCAL.

The S_w calculated by using Eq.4 prefers to be used to estimate initial water saturation while a development well which was drilled after several years of production.

B. Carbonate Oil Wet Reservoir

In this case, a carbonate reservoir is oil-wet (analyzed by previous research). The SCAL data from this reservoir tend to mimic water wet which may be caused by laboratory fluid sample.

The oil reservoir is in the tip formation (upper Oligocene) to Tuban formation of the Lower Miocene. In this formation developed various clastic rocks alternating between clay, limestone, and sand limestone. At the bottom of the formation, there is a massive carbonate rock that is a limestone reef. The cover (cap rock) is Tuban formation and Ngrayong formation of middle-aged Miocene. Tuban carbonate rocks generally consist of mudstone, wackestone, packstone, grainstone, and boundstone with coral fossils, algae, and foramina.

In determining rock type in this formation, pore geometry structure (PGS) method by Wibowo & Permadi (2013) is used (Figure 11), by utilizing data from RCAL. From this method, six rock types are formed in this formation. In this paper, the author added one rock type. Rock type that added to this formation is to define rocks or interval in the formation that considered as a shale break, where this rock type has a very small permeability and porosity, also has initial water saturation value of one. Therefore, this rock type is defined manually, where the value of residual oil saturation (Sor) is zero. The sixth rock type that has been defined as a sequence in which the first rock type is the one that has the best quality and the seventh rock type is the worst. The quality here is to determine or define by the value of its porosity and permeability, which rock type-1 has the highest value of porosity and permeability. In contrast, rock type-6 has the smallest value of porosity and permeability in general.

Figure 12 shows a rock type in each depth. It can be seen that rock type is spread all over the interval,

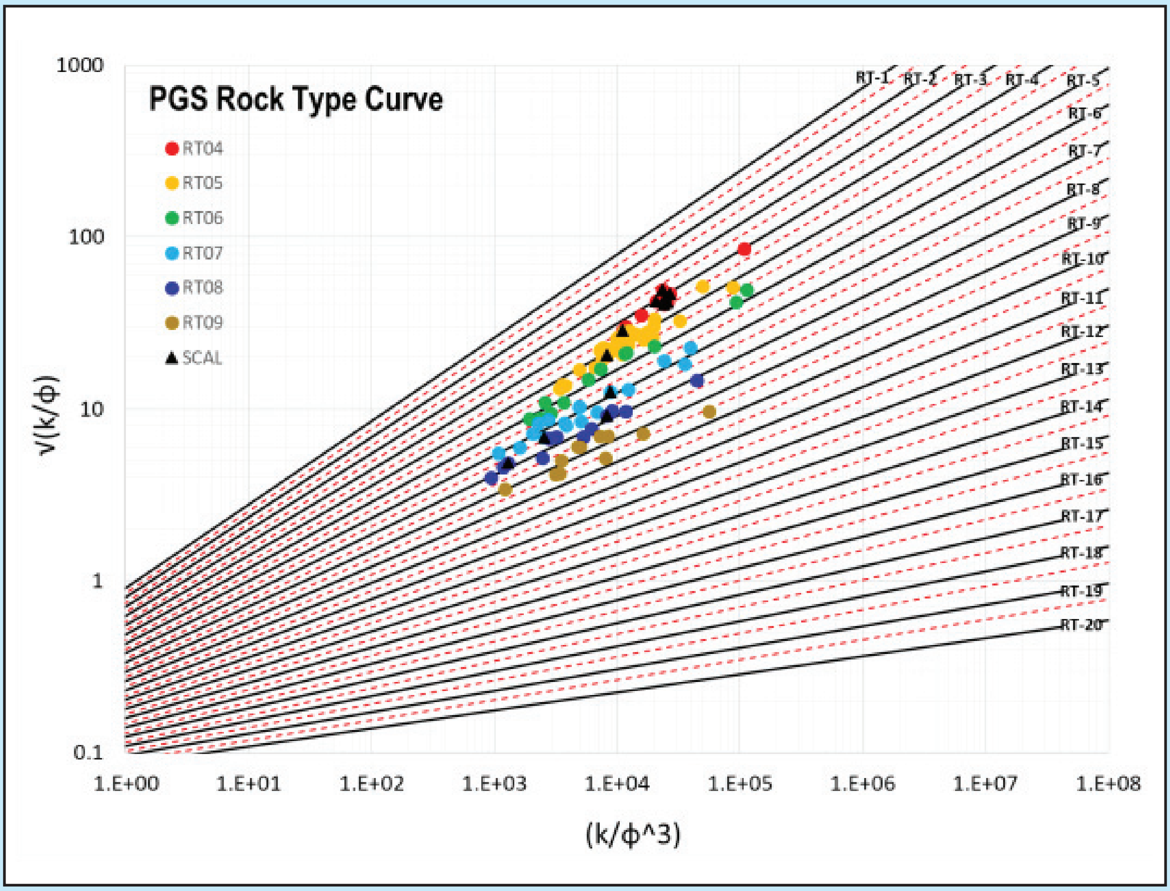

Figure 11
Rock typing by using pore-geometry structure method from RCA data.

in which there is no clear pattern of the rock type distribution. This fact allegedly due to there is a process of diagenesis in each depth, causing rock type is not well distributed in a function of depth.

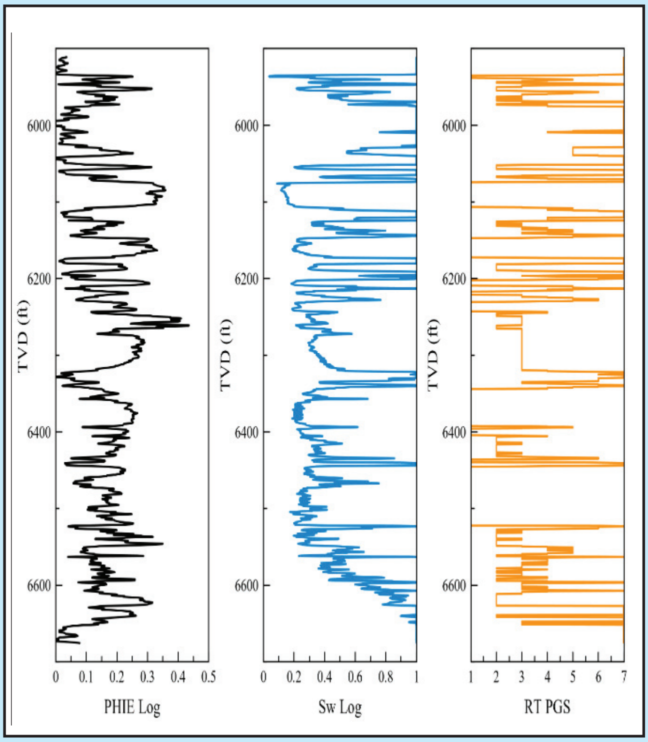

Figure 12
Vertical distribution of rock type and porosity.

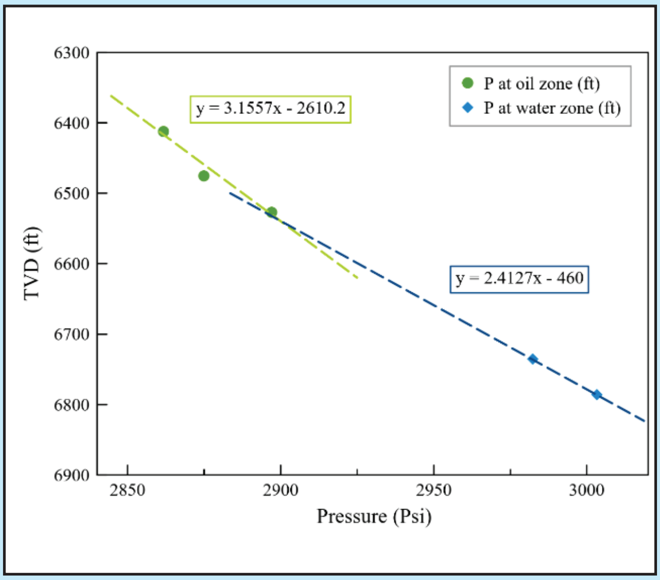

Figure 13
Formation pressure vs depth from RFT and DST data.

Repeat formation tester (RFT) is one of four data that will be integrated into this method. The data from RFT shows the value of P_c which can be converted into oil density and water density, once we know the height of free water level. The plot between pressure vs. depth data from RFT and DST in X field is presented in Figure 13. The pressure at 6412.2 ft, 6475.25 ft, and 6527 ft are contained hydrocarbon. Therefore, the pressure gradient of oil can be determined from those data. It is similar to a water gradient, from the data of pressure vs. depth at 6735.4 ft and 6786.04 ft water gradient can be determined.

The density of water and oil can be determined by converting both oil pressure gradient and water pressure gradient that has value 3.1557 ft/psi and 2.4127 ft/psi respectively, into density, which becomes 0.7318 gr/cc or oil and 0.9572 fr/cc for water. The free water level is obtained by determining the intersection between the oil pressure gradient line and water pressure gradient line, which is in this field is obtained at 6522.2 ft.

The data of oil density, water density, and the free water level is very crucial in this method because those data will be used in determining synthetic P_c, and in creating S_w as a function of depth later on.

Once rock typing has been done, Synthetic P_c and S_w as a function of depth can be constructed. Both parameters are constructed using equation 3.4, in which each rock type has a different equation with another, as mentioned before in the methodology section. The difference lies in the value of P_c^0 and ep, which this value is obtained by iterating the value of initial water saturation calculated to the value of initial water saturation from log data. This can be done because the field formation is supportive for logging data to determine the S_w so that the log data should represent the initial water saturation well enough although it may occur a few errors in particular depth. After iteration is being done by obtaining the smallest error so that the P_c^0 and ep can be determined for each rock type. Table 2 shows P_c^0 and e value for each rock type.

According to Table 2, it can be seen that P_c^0 value is varied, the smallest value is 302.43 that is owned by rock type-1 and the biggest value is 511.13 that is owned by rock type-6. So that ep parameter, which the values vary between 0.92 until 32.3. From this data, it can be concluded that better rock quality indicates lower P_c^0 and higher ep.

Figure 14 shows the final result of initial water saturation as a function of depth from P_c synthetic, also the initial water saturation from logging data. Despite there is a minor difference in a few points, it is obvious that the initial water saturation value is very similar in almost every interval. The error also supports this similarity in the picture by comparing both data, which the root square mean error is 0.0774 and this value is considered very small.

Iterating P_c^0 and ep should do lab data integration. Comparison between P_c vs. S_w data that is obtained from the lab (SCAL) with P_c vs. S_w that is obtained from eq.(2) or synthetic P_c. The initial value of P_c^0 and ep is required to be guessed for running iteration. Once the process is finished, the comparison between P_c vs. S_w in each depth which the SCAL data is available can be made.

Figure 15 shows an example of P_c vs. S_w comparison from sample 10 and 97 which is obtained at depth 6832.5 ft and 6928.5 ft with P_c vs. S_w from the calculation.

In Figure 15, it is evident that there is a significant difference between P_c vs. S_w at the same depth from both data. This is because the data that is obtained from the lab is not reliable. The reason for the unreliableness is, there is a missing procedure in conducting the core testing, where the core that has a character of oil-wet is considered as water wet. The second reason is that the unknown value of interfacial tension value in the reservoir, so that data from the lab cannot be converted into reservoir condition precisely. Moreover, in this case, the lab data become very unreliable, as a consequence is the P_c vs. S_w calculated cannot be integrated with lab or SCAL data.

DST data is integrated with the purpose to validate whether the P_c vs. S_w that is calculated is valid enough or not, especially in the DST interval. The integration is done by comparing water fraction from DST result

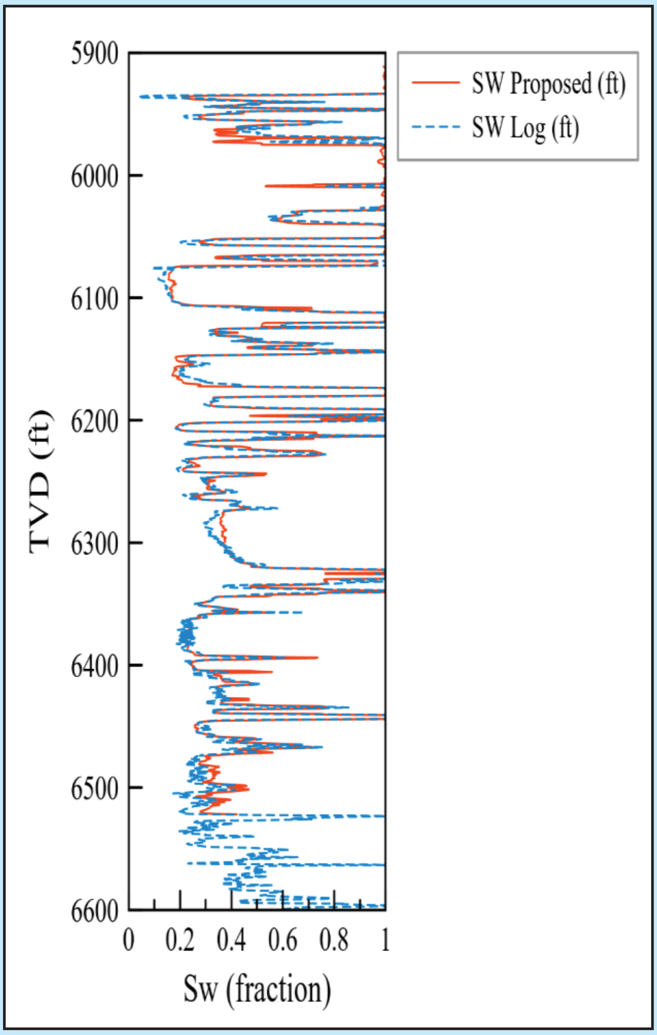

Figure 14
Comparison between initial water saturation from log interpretation and this study calculation.

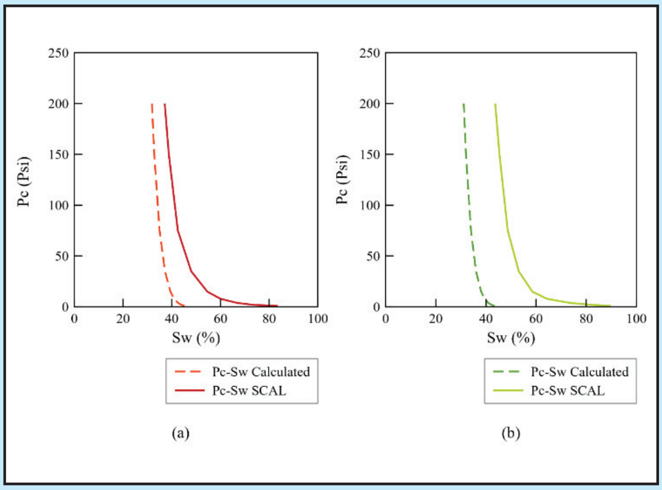

Figure 15
Comparion between Pc vs Sw lab generated and laboratory; a) sample-10 and (b) sample 97.

and from the calculation. The Sw calculation value average in DST test interval is 0.3714. Therefore, the krw and krnw can be obtained from graph krnw vs. Sw as in Figure 10 which is 0.090263 for krw and 0.2878733 for krnw. By applying equation 3.5 to calculate the water fraction, where the viscosity of water and oil is 0.105 cp and 0.429 cp respectively, then the water fraction value is 0.864.

But, because the sample that is obtained from SCAL is not from the same depth as the DST interval, another method is used to calculate the water fraction. This method is made use of Eq.6 and Eq.7 to obtain the k_{rw} and k_{rnw}, where the e_w and e_{nw} is obtained by iterating the calculation k_{rw} and k_{rnw} for each number of S_w value to k_{rw} and k_{rnw} from the same rock type that is obtained from the lab with the same S_w value. After doing the iteration, the e_w and e_{nw} is obtained, which are 2.13 and 2.96. By applying Eq.5, Eq.6, and Eq.7, the water fraction can be obtained, which the value is 0.00355. Meanwhile, by dividing the rate of water by the total liquid rate produced from DST data, the water fraction is 0.126.

RFT data which is used to decide P_c, oil density, water density, and also free water level, is excellent and reliable. It is because, by using those P_c, oil density, water density, and free water level from the RFT, P_c synthetic and S_{wi} value can be constructed and matched with the data from well log. This conclusion is proved by S_{wi} vs. depth between well log interpretation and proposed method calculation which is similar and has a very small error value. Therefore, it can be concluded that RFT data and P_c synthetic can be integrated by confirming each other value.

The fairness of integrating calculated P_c synthetic with logging data can be seen through a comparison of Sw as a function of depth from logging and from calculated, which has a similar value. The similarities are proven by the value of the root mean square error (RMSE) that is very small, with value 0.0774. Also, the graph of S_w vs. depth shows that they are visually alike, despite there are a little different in a few intervals. Those two things show that the result from logging data and synthetic P_c is valid in general. In addition, the log data can be stated as valid data and set as a benchmark to calculate P_c^0 and ep for every rock type is because the formation has no big issue related with resistivity which makes the resistivity log data is reliable in this kind of formation. Therefore, once the P_c synthetic data has a similar value in almost every depth point, the S_w from P_c synthetic can be said as reliable as well.

From the DST data, the production of oil in the interval 6473.2 ft to 6477.3 ft is 1793 bbl/d. Meanwhile, the production of water in the same interval is 259 bbl/d. From those production data, the fraction of water can be calculated, which is 0.12621. In contrast, the water fraction is 0.00355 which is obtained from P_c synthetic by doing the calculation as explained in the case study. It can be seen that there is a significant difference between water fraction from DST and from P_c synthetic calculation. This is allegedly due to water that is recorded by DST is water from mud filtrate. This fact can be concluded because of the result of water produce evaluation from the DST test. Based on the DST, the water contains Cl- which is similar to Cl- that is contained in the mud filtrate. Therefore, it can be concluded that all of the water that is produced in the DST is from mud filtrate. Because of that, there should be no water that is purely produced from the formation or at least only a very small amount. This fact is supported by production history data of this well, where the water cut from this well is 0%. This conclusion is matched with the result from synthetic P_c calculation using fractional flow, which the water fraction is very small. Therefore, in this case, the DST cannot be used as a validator due to the water produced is not water formation.

The result of P_c vs. S_w in the same depth between several samples from the lab does not match with the result of synthetic P_c. This is because there is a lab data error. A missing procedure might cause the error when conducting the core testing, where the core that has the character of oil-wet is considered as water wet so that the data from the lab can be obtained correctly. Therefore, in this paper, P_c synthetic cannot be validated or integrated with the data from the lab due to those reasons.

IV. CONCLUSIONS

The proposed method of integrated initial water saturation modeling has successfully developed in this study. Also, this method has successfully applied in the real field data which has a good result, where the RFT and well log data are successfully integrated or matched with the calculated P_c and S_w. Moreover, integrated water saturation could be applied in any reservoir condition.

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