Field Validation of a Non-logging Alternative Method for the Prediction of the Location of Water-Cresting in Horizontal Wells for Water-Drive Reservoirs

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ABSTRACT: A previously reported method for a non-logging alternative method for the prediction of the location of water-cresting in horizontal wells for water-drive reservoirs is validated in a field test for the first time in this study. Using this method, the wellbore trajectory, variation in the reservoir permeability, and the pressure gradient data were used to calculate what is called the breakthrough coefficient for the different segments along the length of a set horizontal well with the largest calculated breakthrough coefficient corresponding to the most likely location of the actual water-cresting occurrence. This method was field-validated and found to be in good agreement with log testing for a group of seven wells in an oilfield in Northern China. Another calculated parameter derived from the breakthrough coefficient which is called the variation of the breakthrough coefficients that characterize the effect of the variation of water production along the length of the horizontal well due to the effect of the variation of the wellbore trajectory, permeability, and pressure gradient on the oil production is also introduced. This field validation found variation of the breakthrough coefficients to be weakly and inversely correlated to the oil production in application to a group of 27 wells in the same field.

1. INTRODUCTION

Despite accounting for 40% of the growth in the total energy output worldwide, the renewable energy comprised still just 10% of the total energy usage, while oil contributed to 33% at the end of 2019.1 With petroleum being a nonrenewable resource and the ratio of the unconventionals supplying an ever increasing amount to the increasing energy demand worldwide,2,3 there is a need for better stewardship of the existing oil resources to meet the current and future energy/petrochemical needs. The water-drive reservoir characterized by the influx of a natural aquifer for its energy replenishment is a very prolific reservoir type found worldwide with one of the highest recovery efficiencies.4 Despite its higher productivity, the water-drive reservoir produced by vertical wells often quickly runs into the problem of production decline as a result of water coning due to the effect of pressure draw-down.5 As lowering the production rate to lessen the effect of the pressure draw-down in order to delay water coning is often not economically viable, the use of the horizontal well with its inherently lower pressure draw-down and higher productivity compared to the vertical well becomes an attractive option.5,6 However, the use of the horizontal well in a water-drive reservoir does not necessarily get rid of the problem of water coning entirely but merely delays it and changes the geometry of the water breakthrough from that of a point-source water coning to that of a linear water-cresting or cusping.7 For heavy oil reservoir, the problem of water-cresting becomes especially more severe due to the unfavorable mobility ratio.8 With the onset of water-cresting, the productivity of the well rapidly declines,9,10 and in the worst case, it can lead to the well-being entirely flooded out.11 Currently, an assortment of mechanical and chemical...
well interventions$^{12}$ is available involving chemical packers,$^{13–15}$ foam gel,$^8$ cross-linked polymers,$^{16}$ dual completion,$^{17}$ inflow control devices,$^{18–20}$ and so forth. However prior to applying any of these treatment, the location of the water-coning needs to be pinpointed first with specialized logging tools such as the pulsed-neutron three phase holdup measurement tool$^{21}$ or the oxygen activation logging tool.$^{22}$

Due to the commonality of this problem and its effect on production, much work has been conducted for better understanding of the water-coning phenomenon. The research on the topic of water-coning thus far broadly encompassed the theoretical modeling,$^{23–26}$ numerical evaluation,$^{27–30}$ and experimental mechanistic studies,$^{31,32}$ with most of the research focused on the prediction of the critical rate for postponing the water-cresting phenomenon. In 1946, Muscat proposed the first analytical solution modeling the movement of the water−oil interface as a function of the well spacing, ratio of horizontal and vertical permeability, pay thickness, and well penetration for a vertical well in an aquifer−drive reservoir. In 1965, Sobociński and Cornelius derived an empirical model describing the dimensionless height of a water cone versus dimensionless time.$^{34}$ In 1991, Yang and Wattenbarger developed an empirical coning correlation for the prediction of the critical rate, breakthrough time, and water−oil ratio for both the vertical and horizontal wells in the limiting cases when the water−oil mobility ratio is smaller than five or when the viscous forces are not dominating.$^{29}$ Same year, Papatzacos et al. reported a semianalytical solution for the prediction of the breakthrough time as a function of rates for gas/water coning in a horizontal well and found good agreement with the field data.$^{35}$ In 1995, Aulie et al. proposed a steady-state analytical model for the prediction of oil and water production at the supercritical rate and found good agreement with the experimental results carried out with a visual cell at low pressure.$^{35}$ In 1998, de Souza et al. reported a correlation model to predict the breakthrough time, maximum oil rate, and the postbreakthrough behavior of gas and water-coning in both the horizontal and vertical wells as a function of the grid block size, grid patterns, rate, mobility ratio, drainage area, well height, end point, and shape of the relative permeability.$^{36}$ In 2000, Ummuayyoniwat and Ozkan conducted a modeling study on the effect of wellbore pressure drop on the breakthrough time of water and gas coning in horizontal wells and found that wellbore hydraulic has a strong effect on the shape and timing of the breakthrough.$^{37}$ They reported that if the wellbore pressure drop is significant, then coning will take place at the heel and increasing the length of the horizontal wells will not delay the breakthrough. In 2007, Sech et al. conducted parametric analysis and reported that large well diameter and production rate for horizontal wells will result in severe water coning with the only exception being when the vertical permeability relative to the horizontal permeability is poor.$^{38}$ These theoretical studies listed above laid important foundation for the experimental studies that came after. However, due to the complexities of the real reservoirs, the application of these theoretical models in the field has been very limited. A main reason for this is the necessary experimental work needed for the validation of the proposed theoretical models progressed very slowly due to the dearth of sufficiently sophisticated physical modeling tools. This in turns delayed the research progress on the prediction of the likely location of water-coning for early prevention or well intervention.

In 1995, Permadi et al. conducted an experimental study using a Hele−Shaw visual cell with varied oil column thickness, horizontal well length, oil viscosity and reported that the pressure gradient within the wellbore is the main cause of the breakthrough occurring at the heel of the horizontal wells. They reported that the horizontal length of the well and oil column thickness vary inversely with the speed of the breakthrough, and that the rise in water-cuts varies directly with the rise in oil viscosity. Concurring with this study, as the thickness of oil column varies as a function of varying aquifer-to-well distance, the vertical distance between the well and the water−oil interface has also being reported by field operators as a key parameter affecting water-coning.$^{39}$ In 1998, Jiang and Butler conducted an experimental study using the Hele Shaw visual cell and reported that the recovery at breakthrough and the stability of the oil−water boundary varied inversely with the flow rate and the viscosity ratio, except in the case when the high flow rate concurred with the high viscosity ratio, resulting in an apparent higher sweep efficiency due to multiple fingering formation.$^{40}$ In 1999, Dou et al. reported that the permeability variation (i.e., heterogeneity) was found to strongly affect the water-coning phenomenon using a 2D visual cell.$^{35}$ Despite the advances in experimental work using 2D visual cells by many of the previous groups, the intrinsic low pressure and artificial nature of the loose uncemented porous network inherent to this type of low-pressure sand-pack design severely limit its reference value as a physical model for the real reservoir. The development of a better experimental tool for the study of the effect of water-coning phenomenon in horizontal wells for a water-drive reservoir was sorely needed.

In addressing this research problem, the authors recently reported a method that used the pressure data along the well, reservoir permeability, and well trajectory data for the calculation of the distribution of the vertical velocities of the water−oil interface along the length of the well to derive a parameter termed the breakthrough coefficient for quantitating the likelihood of water breakthrough along the length of a horizontal well in a series of sophisticated corefloods using synthetic sandstone models with in-situ pressure and saturation monitoring in real-time.$^{41}$ Incorporating the fundamental parameters of pressure gradient, thickness of the reservoir layer between well and water−oil contact, viscosity, and permeability variation in the characterization of the water-coning phenomenon by other groups, Fu et al. reported a non-logging alternative method for predicting the likely location of water-coning prior to its actual occurrence and provided a way to characterize its relative intensity. This paper continues from the authors’ last report through an application of their reported methodology for a group of seven wells in an oilfield in northeastern China to compare the predicted location of the water-coning occurrence to that of the actual location by logging results. In addition, the variation of the breakthrough coefficient is introduced to help characterize the relative rapidity of the rise of the water-cuts among the different wells in the same field. The validation results using the logging test for these seven wells show that the locations of the water breakthrough matched well to that predicted by the method reported by the authors. Additionally, the variation of the breakthrough coefficient was shown to be useful as a characterizing parameter for ranking the relative intensity of the water breakthrough among the different wells in the same field, with the wells with the larger value of the variation of the
breakthrough coefficient showing faster breakthrough and thus faster water production. The results of this field validation suggest that this non-logging method could be an useful alternative for the prediction of the location and strength of water-cresting in horizontal wells for water-drive reservoir for early prevention or well intervention purposes.

1.1. Geological Setting of the Chosen Field. For the purpose of this field application, a shallow and heterogeneous water-drive reservoir with 22–35% porosity (average porosity of 30%) and permeability of 51.5–5328 × 10⁻³ μm² (average permeability of 1332 × 10⁻³ μm²) located in mid-northern China characterized with the presence of fractures and interlayers was chosen. The reservoir was discovered in 1982 and had gone through three separate stages of development. In order to increase production, horizontal wells were drilled in 2006 with their initial production significantly improved. However quickly thereafter, the reservoirs started experiencing serious problem with high water-cuts as each horizontal well successively started to observe water breakthrough. In response to this problem of high water-cut, well interventions to locate the position of water-cresting in the horizontal wells using the oxygen activation logging tool and well crawler were ordered for these seven chosen wells.

2. METHODS AND PROCEDURE

The mechanistic model used in this work for prediction of the site of water breakthrough is derived from Darcy’s equation. The model takes into consideration key parameters after surveying the published literature. These parameters are pressure gradient along the horizontal portion of the well (\( p_i \)), permeability (\( k_i \)), porosity (\( \Phi_i \)) of the reservoir, height of the water front rising vertically along the length of the horizontal well (\( z_i \)), distance from the top of the aquifer to the well (\( h_i \)), and the aquifer pressure (\( p_a \)). These parameters and how they are related to the water-cresting phenomenon is illustrated in Figure 1. A characterizing parameter called the breakthrough coefficient, as shown in eq 1, is thus defined as the ratio of the average breakthrough time \( T \) of the entire displacement front of a horizontal well to the breakthrough time of a section of the displacement front, \( t_i \), along the horizontal well. For detail derivation of this mechanistic model, please refer to the authors’ previous published paper.

\[
T = \frac{\overline{t}}{t} = \left( \frac{k_i}{k} \right) \left( \frac{\Delta p / h_i}{\Delta \overline{p} / \overline{h}} \right) = R_k R_p / R_h
\]  

(1)

with \( R_k = h_i / \overline{h} \) as the wellbore trajectory coefficient; \( R_k = k_i / \overline{k} \) as the permeability distribution coefficient; and \( R_p = (\Delta p / h_i) / (\Delta \overline{p} / \overline{h}) \) as the pressure gradient coefficient.

The ratio of the height, permeability, and the pressure gradient to their respective average counterparts are the wellbore trajectory coefficient, permeability distribution coefficient, and the pressure gradient coefficient, respectively. The permeability coefficient and pressure gradient coefficient both vary directly with the breakthrough coefficient suggesting that the larger the pressure drop and the higher the pressure gradient, the faster the breakthrough. Similarly, the same is true for the inverse of the wellbore trajectory coefficient (i.e., the smaller the reservoir separation from the aquifer underneath, the faster the breakthrough).

Applying this breakthrough coefficient calculation for a selected well, the horizontal well was first divided into several sections, and the breakthrough coefficients were calculated for each section using the relevant data for the three necessary coefficients at a set interval. Aquifer-to-well distances were calculated by subtracting the wellbore elevation from the elevation of the aquifer. The set of aquifer-to-well distances \( h_i's \) was used to calculate the horizontal wellbore trajectory coefficients \( R_{i, \Delta \overline{p}} \), where \( h_i \) is the elevation of segment \( i \) and \( \overline{h} \) is the average elevation. According to the petrophysical properties of the reservoir for the target well and its neighboring wells, taking into consideration the influence of the inter-layer, the permeability distribution coefficients \( R_k \) of the horizontal well were calculated to derive the average permeability \( \overline{k} \).

Based on the reservoir petrophysical data and the wellbore trajectory data, a model coupling both the wellbore and the reservoir seepage flow was established, with the model revised based on the fluid production volume and pressure drop data. Using this model to calculate the pressure distribution in the horizontal wells, the pressure gradient coefficients \( R_p \) of the horizontal well were thus obtained, where \( \Delta p \) is the pressure difference of segment \( i \) and \( \Delta \overline{p} \) is the average pressure difference. After obtaining the above three coefficients, the breakthrough coefficients for each segment of the horizontal wells were calculated according to eq 1 for the seven test wells.

The breakthrough coefficient is a dimensionless parameter that characterizes the uniformity of the displacement profile of the water−oil interface. The well segment with the highest breakthrough coefficient theoretically will see water breakthrough first, with higher corresponding water production for that segment. Using the well trajectory data, reservoir petrophysical data, the pressure gradient data, the distributions of the breakthrough coefficients along the length of the seven horizontal wells were calculated and compared to the actual liquid production profile by logging tests in the results and discussion section.

Figure 1. Illustration of the water-cresting phenomenon in horizontal wells for water-drive reservoirs (not to scale).
3. RESULTS AND DISCUSSION

3.1. Prediction of the Location of the Water Breakthrough in a Relative Homogeneous Reservoir Layer Using the Breakthrough Coefficient: Comparison of the Logging Results with the Calculated Prediction. Comparison of the location of the water-cresting occurrences as predicted by the largest calculated breakthrough coefficients for four wells in a reservoir with relatively similar horizontal permeabilities to the actual water-cresting location by logging tests is shown.

3.1.1. Case of Large Aquifer-to-Well Distance in a Relative Homogeneous Reservoir Layer. The well G7 is located in a thick reservoir layer with average well distance of 9.8 m to the aquifer, with average permeability of $350 \times 10^{-3} \, \mu \text{m}^2$ according to the petrophysical properties of the same layer in the surrounding wells. The trajectory of the G7 wellbore is shown in Figure 2a with the horizontal section of approximately 200 m in length with the red area shown as the reservoir. The aquifer which lies underneath is not shown. The maximum aquifer-to-well height is found at the heel end at 11.3 m. Figure 2b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficients according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen in Figure 2b, due to the relative thick average aquifer-to-well distance, the effect of the wellbore trajectory deviation in the breakthrough coefficient calculation is seen as negligible (as can be seen in the relative flat appearance of the 1/RH curve). Similarly, as a result of the relative homogeneous nature of the reservoir, the permeability distribution coefficient (RK) is constant along the well. In contrast, the pressure gradient contribution curve (RP) in comparison to the relatively constant values of the two other variables became the dominant factor with the highest relative value nearing the heel. The product of the three coefficients, as shown separately in Figure 2b, is shown as the calculated breakthrough coefficient curve in Figure 2c for comparison to the actual water production results along the length of the horizontal well by logging. As shown in Figure 2c, the place of the highest breakthrough coefficient is taken to be the most likely location of water-cresting occurrence, as discussed in the introduction section. Results in Figure 2c clearly shows that the predicted location of water breakthrough corresponding to the place with the highest calculated breakthrough coefficient agreed well with the actual location of water breakthrough by the logging test.

Figure 2. (a) Wellbore trajectory of the well G7 with the red area shown as the reservoir, the white area underneath the red zone shown as the aquifer (not shown). The wellbore trajectory is marked as the black line. (b) Relative weight of the wellbore trajectory coefficient (···○···), permeability distribution coefficient (---●---), and the pressure gradient coefficient (——) in the calculated breakthrough coefficient. (c) Percentage of the actual liquid production per meter of the producing well segment (hashed bar) compared with the calculated breakthrough coefficient (○-○).
3.1.2. Case of the Absence of a Single Dominating Parameter in a Relative Homogeneous Reservoir Layer. The well G6 is located in a reservoir with average permeability of $190 \times 10^{-3}$ μm$^2$ with relatively similar permeabilities in the horizontal plane. Figure 3a shows the G6 well trajectory. It can be seen from the figure that the horizontal section of the well is about 200 m long, and the production section is composed of two parts. The first production section is within 80 m from the heel. The second production section is within 100 m near the toe end with the aquifer-to-well distance being only 2.2 m.

Figure 3b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficient according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. From Figure 3b, the effect of the higher pressure gradient at the heel (RP curve) is seen to coincide with the effect of the thinner aquifer-to-well distance 20 m away from the heel (1/RH curve), as can be seen from the higher values of the respective two curves at this region. However, the situation became reversed at the toe end of the well, with the effect of the thinner aquifer-to-well distance (1/RH) working in counter to that of the effect of the pressure gradient (RP), as shown by the relative magnitude of the respective curves in this region. Thus for this case, the highest calculated breakthrough coefficient is found at the location 20 m away from the heel, as shown in Figure 3c, which is in good agreement to that of the actual location of water breakthrough by the logging test.

3.1.3. Case of the Short Aquifer-to-Well Distance in a Relative Homogeneous Reservoir Layer. The trajectory of the well G5 wellbore is shown in Figure 4a with the horizontal section about 250 m long. The production section is seen from the figure, as composed of two sections on two side of the dogleg. The first section is within 50 m from the heel end. The second section is within 100 m from the toe end. From Figure 4a, it is very clear that the thinnest part is right in the middle of the well where the dogleg is, very close to the aquifer, with the minimum aquifer-to-well distance of only 2 m. Figure 4b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficient according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen from the relative magnitude of wellbore trajectory coefficient curve (1/RH)
dominating factor in the calculation of the breakthrough coefficient for this case is clearly the wellbore trajectory coefficient. As shown in Figure 4c, the calculated breakthrough coefficient mainly reflects the weight of the thin aquifer-to-well distance, resulting in the highest breakthrough coefficient at the middle of the well suggesting that the water-cresting will most likely be occurring at the middle. This result is supported by the actual logging results with the water production results found to be the highest at the middle, which is in good agreement to the predicted location corresponding to the place of the highest breakthrough coefficient, as shown in Figure 4c.

3.1.4. Case of Weak Pressure Gradient in a Relative Homogeneous Reservoir Layer. The well G3 is located in a reservoir with average permeability of $1100 \times 10^{-3} \mu m^2$. The physical properties of the layer are good, and the permeabilities of each section are relatively close. The trajectory of the wellbore is shown in Figure 5a. The production section of the well is about 100 m long with a concavity in the middle, forming a depressed zone with the thinnest aquifer-to-well distance of 2.8 m. Figure 5b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficients according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen from the relative magnitude of the pressure gradient (RP) and wellbore trajectory coefficient (1/RH) curves in Figure 5b, the effect of the pressure gradient is almost negligible as it being very flat. This resulted in the wellbore trajectory coefficient becoming the sole contributing factor affecting the breakthrough coefficient for this case. As shown in Figure 5c, the calculated breakthrough coefficient curve mainly reflects the weight of the effect of the aquifer-to-well distance, resulting in the highest breakthrough coefficient at the middle-to-latter part of the well. The actual logged water production is shown to be the highest in the second segment of the well, which is in good agreement with the corresponding higher value of the breakthrough coefficient calculated for this region.

3.2. Prediction of the Location of the Water Break-through in a Heterogeneous Layers Using the Break-through Coefficient: Comparison of the Logging Results with the Calculated Prediction. Comparison of the location of water-cresting occurrence, as predicted by the largest calculated breakthrough coefficients for three wells located in reservoirs with heterogeneous horizontal permeability to the actual water-cresting location by logging tests is shown.

3.2.1. Case of the Short Aquifer-to-Well Distance in a Heterogeneous Reservoir Layer. Figure 6a shows the wellbore trajectory plot of the well G2 with the reservoir shown in profile. The reservoir has an average permeability of $650 \times$
−3 μm² with the higher permeability section at the heel end and the lower permeability section at the toe end. According to the wellbore trajectory of well G2, as shown in Figure 6a, the production section of this well is about 150 m. At a distance of 40–80 m from the heel end is the dog leg section with the lowest point at only 1.3 m from the top of the aquifer. Figure 6b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficient according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen from the relative magnitude of the three factors in Figure 6b, it is apparent that the wellbore trajectory coefficient (1/RH) is the dominating factor in the calculation of the breakthrough coefficient. What is unique about this case is that the effects of the higher permeability (RK), thin reservoir distance between the well and the aquifer (1/RH), and the pressure gradient effect (RP) at the heel end favorable for a faster breakthrough all coincide at the heel region. From the results shown in Figure 6c, the calculated breakthrough coefficient is seen to be in good agreement with the actual production results showing breakthrough to occur 20–40 m away from the heel region (Figure 6c).

3.2.2. Case of the Dominating Pressure Gradient in a Heterogeneous Reservoir Layer. Figure 7a shows the wellbore trajectory plot of the well G1 with the reservoir shown in profile. The reservoir has an average permeability of 249 × 10−3 μm² with the lower permeability section at the heel end and the higher permeability section at the toe end. The G1 wellbore trajectory data also show the existence of an interlayer (shown as a white stripe), which splits the reservoir (shown in red) into two partitions, with the aquifer shown as the white region immediately underneath. Figure 7b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficients according to the eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen from Figure 7b, the pressure gradient effect can be seen as the dominant effect in the near heel region in this case, but it logarithmically diminishes further away from the heel. Due to the compounding effect of the coinciding effects of high permeability, thin aquifer-to-well distance, and the high-pressure gradient 60–80 m from the near-heel region, the breakthrough coefficient corresponding to the highest likelihood of breakthrough peaks at 80 m away from the heel.
region, as shown in Figure 7c, which is in good agreement with the actual place of breakthrough according to the logging data.

3.2.3. Case of the Absence of a Single Dominating Parameter in a Heterogeneous Reservoir Layer. Figure 8a shows the wellbore trajectory plot of the well G4 with the reservoir shown in profile. The reservoir has an average permeability of $350 \times 10^{-3} \, \mu m^2$ with the lower permeability section at the heel end and the higher permeability section at the toe end. The G4 wellbore trajectory data also show the existence of an inter-layer (shown in gray), which splits the reservoir (shown in red) into two partitions, with the aquifer shown as the white region immediately underneath. The first segment of the well’s entry into the reservoir is 40 m starting from the heel end in the upper partition. The second part is under the partition which reaches 70 m toward the toe end in the lower partition. Figure 8b shows the comparison of the relative magnitude of the three contributing parameters making up the breakthrough coefficients according to eq 1: the wellbore trajectory coefficient which is shown as the 1/RH curve, the permeability distribution coefficient which is shown as the RK curve, and the pressure gradient coefficient which is shown as the RP curve. As can be seen from Figure 8b, there is no clear dominating factors in Figure 8b making the analysis of which factor is more important in the calculated breakthrough coefficient in this case more difficult. In this case, the effects of higher permeability and thinner separation between the well and the aquifer coinciding at the toe is working against the effect of pressure gradient at the heel. The results of the interplay of these parameters on the effect of the actual water production juxtaposed with the calculated breakthrough coefficient is shown in Figure 8c. Despite the general agreement for the site of breakthrough by both the logging test and the breakthrough coefficient calculation method all pointing toward the toe region, the actual logging test data show that the production at the toe is only slightly more on a per unit length basis than at the heel region suggesting that there might be more uncertainties in predicting the site of water breakthrough using this water breakthrough coefficient method when there is no single dominating parameters (i.e., when the magnitude of the curves for the wellbore trajectory coefficient, the permeability distribution coefficient, and the pressure gradient coefficient are all similar).

3.3. Characterization of the Effect of the Variation of the Breakthrough Coefficient on the Rise in Water-Cuts. A method of predicting the breakthrough location in horizontal wells for water-drive reservoirs using the breakthrough coefficient as a characterizing parameter is validated by field results in this work. On this basis, using the breakthrough

Figure 6. (a) Wellbore trajectory of the well G2 with the red area shown as the reservoir, the blue area underneath the red zone as the aquifer. The wellbore trajectory is marked as the black line. (b) Relative weight of the wellbore trajectory coefficient (···○···), permeability distribution coefficient (-●-), and the pressure gradient coefficient (―) in the calculated breakthrough coefficient. (c) Percentage of the actual liquid production per meter of the producing well segment (hashed bar) compared with the calculated breakthrough coefficient (○-○).
coefficient, a method of characterizing the rapidity of the rise in water-cuts and its subsequent effect on the oil production as a result of the water-cresting event using a breakthrough coefficient derived-parameter called the variation of the breakthrough coefficients. In short, variation of the breakthrough coefficients characterizes the effect of the variation of the calculated water breakthrough coefficients in a horizontal well due to the three major factors (heterogeneity, aquifer-to-well distance, and wellbore pressure gradient) and its subsequent effect on oil production. Theoretically, the bigger the variation in the distribution of the oil-water interface along the well, the faster the water breakthrough, the faster the rise in water-cuts, and the greater the impact on oil production. However, due to the production interference introduced by the inter-layers, this application is only limited to reservoirs without the presence of inter-layers.

\[ E_w = \sum_{i=1}^{n} \left( T_{wi} - \bar{T}_w \right)^2 \bar{T}_w^{-2} \]  

(2)

3.3.2. Effect of the Variation of the Breakthrough Coefficients \( E_w \) on the Rise in Water-Cuts. The plots of the water-cuts versus the production period for the four wells (well G1, G2, G3 in the same field A, and the well G7 from a different field B) with the available production history data are shown in Figure 9. The calculated variation of the breakthrough coefficients for these four wells are 17.55, 6.77, 1.17, and 0.23, respectively, for the wells G1, G2, G3, and G7. Comparing the wells G1, G2, and G3, the production water-cuts for the well G1 exhibits a significant delay in the rise in the water-cuts (Figure 9a) despite having the highest variation of the breakthrough coefficients, which is attributed to the presence of the inter-layer, as shown in Figure 7a. Comparison of the well G2 and G3 in Figure 9b–c shows that G2 with roughly six times the variation of the breakthrough coefficients than G3 clearly exhibits a much steeper rise in water-cuts. Figure 9d shows the rise in water-cut for well G7 from a different field B with a very low value of the variation of the breakthrough coefficients at 0.23 which can be mostly

Figure 7. (a) Wellbore trajectory of the well G1 with the red area shown as the reservoir, the white band across as the inter-layer, and the white area underneath the red zone as the aquifer. The wellbore trajectory is marked as the black line. (b) Relative weight of the wellbore trajectory coefficient (…○…), permeability distribution coefficient (…●…), and the pressure gradient coefficient (…) in the calculated breakthrough coefficient. (c) Percentage of the actual liquid production per meter of the producing well segment (hashed bar) compared with the calculated breakthrough coefficient (…●…).
attributed to it having the largest aquifer-to-well distance (Figure 2a).

In Figure 10, a plot of the maximum production ratio per meter over minimum production ratio per meter (hereafter called the ordinate quantity) versus variation of the breakthrough coefficients is shown. The maximum production ratio per meter is the maximum percentage of the actual liquid production per meter of the producing well segment in Figures 2–8c’s, while the minimum production ratio per meter is the minimum percentage of the actual liquid production per meter of the producing well segment in Figures 2–8c’s. In another word, the ordinate quantity (●) in Figure 10 is the ratio of the difference in the magnitude between the maximum and minimum logged water production (e.g., the ordinate quantity in Figure 9 for well G3 is 3 for the corresponding variation of the breakthrough coefficients of 1.16). The correlation factor between the ordinate quantity and the variation of the breakthrough coefficients in Figure 10 is 0.87 [not including the two wells with the presence of inter-layer (○)], suggesting that there is a high degree of correlation between these two variables. This suggests that the higher the variation of the breakthrough coefficients, the greater the disparity of water production in different segment of a horizontal well.

3.3.3. Effect of Variation of the Breakthrough Coefficient $E_w$ on the Oil Production. If a high variation of the breakthrough coefficients is strongly correlated to a fast rise in water-cuts, then the next question to ask is how does it affect the oil production. In Figure 11, a plot of the dimensionless oil production versus the calculated variation of the breakthrough coefficients according to eq 2 for the 27 wells in the same field as the G1-7 wells used in this study is shown. Here, the dimensionless oil production is derived by dividing the production of each well in cubic meters to the volume of the well in cubic meters. With the exception of G2 and G3, marked by red diamonds, the rest of the wells in Figure 11 are not logged for water production but merely have their dimensionless oil production plotted against their calculated variation of the breakthrough coefficients. The five other wells that are logged for water production shown in Figures 2–8 are excluded from this data set, as shown in Figure 11, due to the high instances of work-overs or use of the higher pressure draw-down maneuvers to increase oil production that makes the fair comparison to the recovery by natural energy with the rest of the wells more difficult. Two objective observation can be made from Figure 11. The first observation is that the dimensionless oil production and the breakthrough coefficient is weakly and inversely correlated with each other with the correlation factor of $-0.38$. The second observation is that despite the scatter, there is a general trend that suggests that the higher the variation of the breakthrough coefficients, the

Figure 8. (a) Wellbore trajectory of the well G4 with the red area shown as the reservoir, the gray area as the inter-layer, the white area underneath the red zone as the aquifer. The well is marked as the black line. (b) Relative weight of the wellbore trajectory coefficient (⋯○⋯), permeability distribution coefficient (●), and the pressure gradient coefficient (—) in the calculated breakthrough coefficient. (c) Percentage of the actual liquid production per meter of the producing well segment (hashed bar) compared with the calculated breakthrough coefficient (○).
lower the oil production. According to Figure 11, the higher oil production is predominantly concentrated in the zone with the lower variation of the breakthrough coefficients. Interpretation of the significance of this observation suggests that the wells with the flatter breakthrough front as characterized by a more uniform distribution of the calculated breakthrough coefficients will see a slower rise in water-cut and therefore a higher oil production. In the limiting case when the breakthrough coefficient is uniform along the entire length of a horizontal well, then the breakthrough coefficient = 1, variation of the breakthrough coefficients also = 0, and the oil production would approach the maximum at breakthrough. Conversely, in an actual reservoir, the greater the variation of the breakthrough coefficients, the more uneven the water-cresting front, and the faster the breakthrough, the faster the rise in water-cuts, resulting in a lowered oil production overall.

4. CONCLUSIONS

(1) The results of this field validation show good agreement between the locations of the actual water breakthrough from log testing to the segments predicted by the non-logging method introduced by the authors corresponding to the highest calculated breakthrough coefficients for a group of seven test wells.

(2) The variation of the breakthrough coefficients was found to be an useful parameter in sorting the relative production performance of wells in the same field. For a group of 27 wells in the same field as the seven test wells used as examples in this paper, the variation of the
breakthrough coefficients was found to be weakly and inversely correlated to the oil production.

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