Improved Characterization and Modeling of Capillary Transition Zones in Carbonate Reservoirs


Summary
An oil/water capillary transition zone often contains a sizable portion of a field’s initial oil in place, especially for those carbonate reservoirs with low matrix permeability. The field-development plan and ultimate recovery may be influenced heavily by how much oil can be recovered from the transition zone. This in turn depends on a number of geological and petrophysical properties that influence the distribution of initial oil saturation ($S_o$) against depth, and on the rock and fluid interactions that control the residual oil saturation ($S_{or}$), capillary pressure, and relative permeability characteristics as a function of initial oil saturation.

Because of the general lack of relevant experimental data and the insufficient physical understanding of the characteristics of the transition zone, modeling both the static and dynamic properties of carbonate fields with large transition zones remains an ongoing challenge. In this paper, we first review the transition-zone definition and the current limitations in modeling transition zones. We describe the methodology recently developed, based on extensive experimental measurements and numerical simulation, for modeling both static and dynamic properties in capillary transition zones. We then address how to calculate initial-oil-saturation distribution in the carbonate fields by reconciling log and core data and taking into account the effect of reservoir wettability and its impact on petrophysical interpretations. The effects of relative permeability and imbibition capillary pressure curves on oil recovery in heterogeneous reservoirs with large transition zones are assessed. It is shown that a proper description of relative permeability and capillary pressure curves including hysteresis, based on experimental special-core-analysis (SCAL) data, has a significant impact on the field-performance predictions, especially for heterogeneous reservoirs with transition zones.

Introduction
The reservoir interval from the oil/water contact (OWC) to a level at which water saturation reaches irreducible is referred to as the capillary transition zone. Fig. 1 illustrates a typical capillary transition zone in a homogeneous reservoir interval within which both the oil and water phases are mobile. The balance of capillary and buoyancy forces controls this so-called capillary transition zone during the primary-drainage process of oil migrating into an initially water-filled reservoir trap.

Because the water-filled rock is originally water-wet, a certain threshold pressure must be reached before the capillary pressure in the largest pore can be overcome and the oil can start to enter the pore. Hence, the largest pore throat determines the minimum capillary rise above the free-water level (FWL). As shown schematically in Fig. 2, close to the OWC, the oil/water pressure differential (i.e., capillary pressure) is small; therefore, only the large pores can be filled with oil. As the distance above the OWC increases, an increasing proportion of smaller pores are entered by oil owing to the increasing capillary pressure with height above the FWL. The height of the transition zone and its saturation distribution is determined by the range and distribution of pore sizes within the rock, as well as the interfacial-force and density difference between the two immiscible fluids.

The transition zone may vary in thickness from a few meters in high-matrix-permeability (function of pore-size distribution) reservoirs to more than 100 m in some low-permeability reservoirs such as tight carbonates, and therefore it may contain a significant portion of the reservoir’s oil in place. This zone is often not perforated for oil production because it is considered uneconomic and compounded by water-production and handling issues expected from the first day of production. In the literature, numerous studies have been published on the potential and importance of the capillary transition zone (Land 1968; Killoough 1976; Kleppe et al. 1997; Masalmeh and Oedai 2000; Masalmeh 2000; Larsen et al. 2000; Sarwaruddin et al. 2001; Christiansen et al. 1999; Fanchi et al. 2002; Eigestad and Larsen 2000; Parker and Rudd 2000; Ghedan et al. 2004). These studies address various aspects of capillary transition zones, including initial fluid distributions, residual oil saturation ($S_{or}$) vs. initial oil saturation ($S_o$) correlations, and relative permeability and capillary pressure models for dynamic modeling of transition-zone recovery.

Reservoir wettability may vary as a function of height above the FWL and initial water saturation. This variation in wettability can be attributed to changes in initial oil saturation as a result of changes in capillary pressures. Our experience in a number of carbonate reservoirs in the Middle East shows that the fraction of oil-wet pores increases as the oil saturation increases with height above the FWL and that the wettability of the pores filled with oil may change to oil-wet or mixed-wet even at oil saturations below 20 to 30% (Masalmeh 2002, 2003). Therefore, it is critically important that the representative reservoir wettability condition is preserved or restored in laboratory data acquisition, and specially designed experimental procedures are required for capillary transition zones to mimic the wettability behavior and initial-oil-saturation variation as a function of depth.

In the following sections, we will first address the aspect of static modeling to determine the initial oil distribution vs. height above the FWL, by integrating log data and core-derived saturation-height functions. This will be followed by dynamic modeling of saturation functions to characterize relative permeability and imbibition capillary pressure bounding and scanning curves as a function of different initial oil saturations. The dependency of residual oil saturation on initial oil saturation also will be investigated. Carbonate-field examples will be shown to highlight the importance of experimental measurements and correct implementation of SCAL data in reservoir simulation for understanding and predicting waterflood recovery from capillary transition zones.

Initial Water Saturation in the Transition Zone
The initial fluid-saturation distribution in the transition zone is a key issue that affects both static [estimation of stock-tank oil initially in place (STOIIP)] and dynamic (hydrocarbon production and recovery) modeling. The saturation-height function can be calculated with saturation logs, drainage capillary pressure curves measured on representative core samples, or (preferably) a combination of log- and core-based approaches. The calculation of in-situ saturation from resistivity logs requires knowledge of the
“resistivity index curve,” which can be measured reliably only on reservoir core material in the laboratory under representative in-situ conditions (Jing et al. 1993).

For both log- and core-based saturation evaluations, drainage is generally considered as the process that took place when hydrocarbon migrated to the reservoir. There are exceptions to this general assumption; for example, imbibition capillary pressure curves may be needed for certain parts of the reservoirs that had undergone water encroachment because of production, leakage, tilting, or other hydrodynamic effects. Another exception in which the drainage process is not applicable is in-situ hydrocarbon generation; hence, the reservoir rock is also the source rock.

The drainage capillary pressure curves are usually measured on water-wet rocks using refined-oil/water, gas/water, or mercury/air systems. The measured capillary pressure curve is then converted to reservoir conditions by correcting for the interfacial tension (IFT) and contact-angle (θ) differences as well as the effect of confining stress. This is to mimic the initial hydrocarbon migration into the reservoir initially 100% water-saturated and, hence, strongly water-wet. The water-wet condition may change after the oil migration if the oil phase disrupts the molecular water film and polar components from oil come in contact with the pore surfaces. It is generally assumed that primary-drainage capillary pressure curves measured with model fluid systems on cleaned core samples should still represent the reservoir crude-oil/brine systems, subject to the necessary conversions of IFT and θ effects.

Fig. 3 shows an example of a comparison of primary-drainage capillary pressure using laboratory (mercury/air) and reservoir (crude-oil/brine) fluid pairs, and a close agreement was observed for this carbonate reservoir.

The saturation-height distribution can also be derived from resistivity logs using Archie-type equations calibrated against laboratory core measurements (Archie 1942). It has been observed, however, that in carbonate reservoirs, the Archie saturation exponent (n) derived from water-wet drainage systems may not be the same as that derived using crude-oil/brine systems in which the reservoir wettability is restored (van der Post et al. 2000). As a result, the saturation-height function derived from resistivity logs using the water-wet Archie saturation exponent can be significantly different from that derived from drainage $P_c$ curves. As shown schematically in Fig. 4, an increase in saturation exponent (i.e., non-Archie resistivity-index behavior) is often observed in oil-wet carbonates as water saturation decreases at a relatively high position above the FWL.

In a water-wet formation, water remains continuous throughout the pore network, even at low connate-water saturations, and provides a conducting path for electric current. As wettability starts to change, oil disrupts the water film and comes in direct contact with the rock surface, causing the water film to lose continuity. For relatively high water saturations, the change in wettability is not expected to affect the resistivity of the rock because water is still connected through most of the pore network and, therefore, the formation resistivity is similar to that of the water-wet formation. As water saturation decreases, the conducting brine phase becomes more discontinuous, and its ability to contribute to the electrical conductivity is impaired. It leads to a rapid increase in the resistivity as water saturation decreases further and results in higher $n$ values. This shows that the saturation exponent depends on the initial oil saturation and varies across the capillary transition zone for mixed-wet and oil-wet reservoirs (Jing et al. 1993; Fleury 2002). For oil-wet carbonates, $n$ typically may increase from ap-

Fig. 1—Schematic diagram to show the capillary transition zone.

Fig. 2—Initial oil distribution as a function of height above the FWL and its relation to pore-size distribution (black-shaded portion shows pores occupied by oil).

Fig. 3—Comparing centrifuge to mercury/air $P_c$ curves for two different samples: (a) high permeability with multimodal pore-size distributions and (b) low permeability; solid line is mercury/air, and points are centrifuge data.

Fig. 4—Wettability effects on the resistivity-index-vs.-saturation relationship, with the corresponding micromodel pictures showing the conducting brine phase in red/darker color. Points A and B are water-wet, and Points C and D are oil-wet.
proximately 2 to greater than 3, depending on wettability and initial water saturation. In such cases, the saturation-height functions calculated from resistivity logs using the water-wet saturation exponent may lead to overestimation of the hydrocarbon saturation, especially toward the top of the transition zone. On the other hand, if a constant $n$ measured after restoring reservoir wettability at irreducible water is used, the calculated saturation-height function from logs may result in underestimation of the hydrocarbon saturation through the transition zone. In this case, a saturation-dependent $n$ (i.e., nonlinear resistivity index vs. saturation on an Archie plot) can give the correct saturation-height function.

This non-Archie resistivity index vs. saturation relationship can be measured in a drainage experiment after aging the core samples with reservoir crude oil at different water saturations following the primary-drainage direction. The recommended practice is to reconcile the saturation vs. height distributions by comparing the capillary-pressure-derived saturations vs. those derived from resistivity logs following the above wettability considerations. Often, additional data [e.g., direct Dean-Stark saturation measurements using cores taken with oil-based mud (here, water mobility could be an issue; hence, it is more reliable toward the top of the transition zone)] and other saturation logs (such as pulsed-neutron-capture logs with due quality checks and modeling) are helpful in reducing the uncertainty of initial water-saturation distribution in a capillary transition zone.

The assumption that initial saturation distribution in a reservoir follows a primary-drainage capillary pressure curve needs to be examined carefully on a field-well-specific basis. In some areas, oil might have been displaced by imbibition during the fluid-migration history following the initial primary drainage. Hence, if there is field evidence to suggest possible movement of the FWL after the initial oil migration, then imbibition resistivity index and capillary pressure curves should be used to determine the initial saturation distribution in the field. For reservoirs with tilted fluid contacts, some further imbibition/drainage process may take place after the initial oil migration, leading to changes in the saturation distribution. Drainage capillary pressure data may reflect only the saturation distribution of the part of the reservoir that did not undergo any saturation change after initial charging, whereas both drainage and imbibition capillary pressure and resistivity index curves are required for the parts that may have experienced an increase in water saturation. This needs to be taken into account carefully in the interpretation of initial water saturation in capillary transition zones.

**Dynamic Modeling of Transition-Zone Behavior**

For proper dynamic modeling of the transition zone, we need to incorporate the residual-oil-saturation ($S_{or}$)/initial-oil-saturation ($S_{oi}$) relationship and apply relative permeability and capillary pressure models that are calibrated against experimental data and honor the correct physical characteristics of the capillary transition zone. The amount of recoverable oil in a transition zone depends on the distribution of initial oil saturation ($S_{oi}$) as a function of depth (the $S_{or}/S_{oi}$ relationship), as well as the general relative permeability and capillary pressure characteristics.

The most frequently used correlation to predict residual saturation is the empirical relation by Land (1968), based on matching experimental data for a gas/water system. However, recent SCAL studies showed different $S_{or}/S_{oi}$ correlations (Klepe et al. 1997; Masalmeh and Oedai 2000; Masalmeh 2000; Larsen et al. 2000; Sarwaruddin et al. 2001). These models assume that the residual oil saturation depends on the maximum attained oil saturation. The more pores filled with oil in the drainage process, the more oil can be trapped in the subsequent imbibition and, thus, the larger the residual oil saturation. However, some of the existing models such as the Land correlation have not been calibrated on carbonates with representative reservoir wettability. Therefore, using the Land correlation to relate residual oil saturation ($S_{or}$) to initial oil saturation ($S_{oi}$) for mixed-wet/oil-wet reservoirs may lead to erroneous predictions, and SCAL experimental verification is always required.

In addition to the $S_{or}/S_{oi}$ relationship, relative permeability of oil and water, as well as imbibition capillary pressure curves starting at different initial oil saturations, is also needed for transition-zone reservoir simulation. However, there is very limited reliable data on the dependence of relative permeability and capillary pressure on initial oil saturation applicable to capillary transition zones in mixed-wet and oil-wet systems. As a result, in reservoir simulations, simplified approximations and empirical correlations are often used. One common approach uses residual oil saturations, as well as imbibition relative permeability and capillary pressure curves that are measured at the maximum initial oil saturation (i.e., the so-called bounding imbibition relative permeability and capillary pressure curves). In this case, the dependency of relative permeability and capillary pressure on $S_{oi}$ through the capillary transition zone is ignored, and the RP can be highly underestimated. Another approach, as generally available in some commercial reservoir-simulation packages, is based on empirical correlations, which have a dependency on residual oil [e.g., the Land model (1968)] and relative permeability [e.g., the Killough hysteresis model (1976)] as a function of initial oil saturation.

However, the currently available hysteresis models have the following shortcomings, which may have important implications for modeling transition zones in carbonates:

- **Use of the Land correlation**, which is based on gas/water or gas/oil data.
- **Wettability characteristics** are not fully taken into account because water-wetting is assumed in early hysteresis models (Killough 1976). However, Skjaeveland et al. (1998) and Kjosavik et al. (2002) have recently published hysteresis models for mixed-wet reservoirs that have addressed this limitation of the earlier models.
- **A lack of relevant experimental data** to calibrate relative permeability and capillary pressure dependency on initial oil saturation.
- **Capillary pressure models** assume that bounding and scanning curves form closed loops (Skjaeveland et al. 1998).

In this study, multiphase displacements in the transition zone have been characterized by experimentally measuring residual oil saturation ($S_{or}$) and relative permeabilities and capillary pressures at various initial oil saturations following proper wettability restoration, a combination of SCAL experiments and numerical interpretation of experimental data using simulation. The experimental procedure is described in Masalmeh and Oedai (2000). In the following sections, we will discuss mathematical models that have been developed to generate the $S_{or}/S_{oi}$ correlation, as well as the relative permeability and capillary pressure scanning and bounding curves.

**Initial-Oil/Residual-Oil-Saturation ($S_{or}/S_{oi}$) Correlation**

The initial oil saturation at the end of the drainage experiments and the residual oil saturation after the imbibition experiments for different reservoirs are shown in Fig. 5. The data show two different trends for $S_{or}/S_{oi}$ correlations:

![Fig. 5—$S_{or}/S_{oi}$ correlation for two fields: (a) data follow Eq. 1, and the high $S_{or}$ values are measured on plugs of different (vuggy) pore-size distribution; (b) data show almost linear correlation (Eq. 2); the different symbols denote different wells.](image)

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(1) Linear trend with \( S_{or} \) plateau:

\[
S_o(S_o) = S_{or}^{\max} \quad S_o = S_{or}c, \quad \text{..........................} \quad (1a)
\]

\[
S_o(S_o) = \frac{S_o \times S_{or}^{\max}}{S_{or}c} \quad S_o < S_{or}c, \quad \text{..........................} \quad (1b)
\]

where \( S_{or}^{\max} \) is the maximum residual oil saturation and \( S_{or}c \) is the maximum initial oil saturation above which there is no dependency of \( S_o/S_{or} \). For the example shown in Fig. 5a, \( S_{or}^{\max} = 0.07 \) and \( S_{or}c = 0.20 \). Although only a few experimental data points are available below \( S_{or}c \), with the physical anchoring point at \( S_o = S_{or} = 0 \), a linear sloping trend is assumed for initial oil saturation below \( S_{or}c \).

(2) Linear Correlation:

\[
S_o(S_o) = \frac{S_o \times S_{or}^{\max}}{S_{or}c}, \quad \text{..........................} \quad (2)
\]

where \( S_{or}^{\max} \) is the maximum initial oil saturation.

In some cases, the Land correlation (1968) or other functional forms (e.g., polynomial) may also work, provided that SCAL data are available to calibrate the correlations. Therefore, in the following derivations, we refer to the general residual and initial oil dependency as the \( S_o/S_{or} \) relationship without restricting it to any specific empirical trend.

It is worthwhile to note that the \( S_o/S_{or} \) correlation is not the only factor that determines oil recovery. The simple relation between \( S_o/S_{or} \) does not mean that the residual oil saturation in the transition zone can be reached after waterflooding of limited pore volumes (PV). Residual oil saturation (defined as oil relative permeability equal to zero) can be obtained only after an infinite number of PV have been injected (i.e., if waterflooding is sustained for a very long time). In most cases, only the remaining oil saturation (ROS) (i.e., oil with some degree of mobility remaining) can be achieved. This remaining oil is mainly determined by the oil relative permeability curve close to residual oil saturation.

**Oil Relative Permeability Model**

For accurate prediction of oil mobility in the transition zone, a physically sound model is needed to describe the dependence of residual-oil saturation and imbibition oil relative permeability on initial oil saturation. We propose a modified Corey model to generate the relative permeability scanning curves that match the experimental data:

\[
k_o = k_o(S_o) \times \left[ S_o - S_o(S_o) \right] \frac{n_o(S_o)}{S_{or}^{\max} - S_{or}(S_o)}, \quad \text{..........................} \quad (3)
\]

where \( S_o(S_o), k_o(S_o), \) and \( n_o(S_o) \) are the residual oil saturation, the oil endpoint relative permeability, and the Corey exponent, respectively, and \( c(S_o) \) is a constant to adjust the oil relative permeability close to residual oil saturation to describe the film flow regime. This constant is determined experimentally because we found that the Corey model (first term alone) could not match some experimental data. Note that the relative importance of the second term increases as the oil Corey exponent increases.

To generate a full set of bounding and scanning relative permeability curves, the following parameters need to be defined for each \( S_o \) value at a given height above the FWL:

- The residual oil saturation as a function of initial oil saturation, \( S_o(S_o) \), can be measured experimentally and fitted with one of the \( S_o/S_{or} \) relationships described in the above section.
- The oil relative permeability at initial oil saturation \( k_o(S_o) \) should be measured on samples aged at various \( S_o \). We have found that, in general, \( k_o(S_o) \) can be described by the bounding primary-drainage oil relative permeability curve, although it does not have to follow the primary-drainage curve.
- The Corey exponent \( n_o(S_o) \) and the parameter \( c(S_o) \) are variables used to generate the relative permeability curves that can fit the experimental data closely. They can be defined as follows:

\[
n_o(S_o) = n_o(S_{or}^{\max}) + b_1 \times (S_{or}^{\max} - S_o)^2, \quad \text{..........................} \quad (4)
\]

\[
c(S_o) = c_{max} \quad \text{..........................} \quad (5)
\]

where \( n_o(S_{or}^{\max}) \) and \( c_{max} \) are the oil Corey exponent and the constant \( c(S_o) \) at the highest initial oil saturation, respectively, and \( b_1 \) and \( b_2 \) are fitting parameters. From our experience, the parameter \( c_{max} \) is usually <0.005, and for all practical purposes, \( b_1 \) and \( b_2 \) can be set to zero and, hence, the oil Corey exponent for the oil scanning curves can be assumed constant (i.e., independent of \( S_o \)) and remains the same as in the bounding imbibition curve. To generate the curves based on experiments, shown in Fig. 6, we used the following parameters: \( S_{or}^{\max} = 0.9, k_o(S_{or}^{\max}) = 0.7, n_o(S_{or}^{\max}) = 3.5, c_{max} = 0.003, b_1 = 0, \) and Eq. 1 for \( S_o/S_{or} \). The oil endpoints were generated with the primary-drainage bounding curve. Oil relative permeability curves for each \( S_o \) are generated by substituting the parameters defined in Eqs. 1, 2, 4, and 5 into Eq. 3.

As shown in Fig. 6, for a given oil saturation, oil is more mobile because initial oil saturation decreases compared to its corresponding value following the bounding imbibition curve. This figure also shows that the ROS at a certain oil relative permeability cutoff value may have a different dependence on \( S_o \) compared to residual oil saturation. ROS can be more than 10% higher than \( S_{or} \) for high initial oil saturation, but it approaches \( S_{or} \) as \( S_o \) decreases. In other words, although the residual oil is the same in this case, it is approached faster when oil is located closer to the OWC. The recoverable oil is determined by ROS at a certain \( k_o \) cutoff value, rather than the residual oil saturation, which in many cases may be unattainable during the field life.

To explain this behavior, let us suppose that all the pores filled with oil in the primary drainage are rendered oil-wet (which seems to be the case for a large number of carbonate reservoirs in the Middle East); then, in the imbibition cycle, water will start displacing oil from the biggest pores first regardless of the initial oil saturation. Therefore, moving down the transition zone, oil becomes relatively more mobile (i.e., has higher relative permeability for the same saturation) as it occupies progressively larger pores moving toward the OWC.

**Water Relative Permeability Model**

From our available data set, very little hysteresis was observed in the water relative permeability curves through the capillary transition zone. Therefore, the water-drainage bounding curve (described by Eq. 6) is often used as an approximation in the water relative permeability model for transition zones. However, in the case of significant hysteresis being observed, the water relative permeability scanning curves can be generated with the following Corey model:

\[
k_w = k_w(S_w) \times \left( \frac{S_w - S_{cw}}{1 - S_{cw}} \right)^{n_w}, \quad \text{..........................} \quad (6)
\]

\[
k_w^{ib}(S_w) = k_w(S_w) \times \left( \frac{S_w - S_{cw}}{1 - S_{cw}} \right)^{n_w}, \quad \text{..........................} \quad (7)
\]

where \( k_w(S_w) \) is the water Corey exponent \( n_w \) for imbibition and is assumed constant for all scanning curves unless data shows otherwise; and
$S_{wi}$ is a mathematical solution to ensure that the water imbibition scanning relative permeability curve and bounding drainage relative permeability curve $k_{rel}^d(S_{wi})$ are equal at $S_{wi}$ (i.e., the imbibition water scanning relative permeability curve originates from the bounding drainage curve). The value of $S_{wi}$ can be obtained from Eqs. 6 and 7 as follows:

$$S_{wi} = \frac{1 - k_{rel}^d(S_{wi})}{k_{rel}^d(S_{wi})} \left[ 1 - \frac{1}{k_{rel}^d(S_{wi})} \right]$$ .......................... (8)

In case no experimental data are available for $k_{rel}^d(S_{wi})$, we assume a linear interpolation between $S_{wi}$ and 1, and it is given by

$$k_{rel}^d(S_{wi}) = 1 - S_{wi} \left[ 1 - \frac{1}{k_{rel}^d(S_{wi})} \right]$$ .......................... (9)

The above mathematical formulae can be used to generate water relative permeability scanning curves for general cases in which the imbibition bounding curve is either higher or lower than the drainage bounding curve. Experimental data are required to verify and calibrate the above water relative permeability scanning model.

**Capillary Pressure Model**

The measured bounding drainage ($P_{cd}$) and bounding imbibition ($P_{ci}$) capillary pressure curves can be fitted with the following mathematical formulae given by Eqs. 10 and 11.

$$P_{cd} = \frac{c_{cd}}{S_{wi} - S_{wb}} \left[ 1 - S_{wi} - S_{wb} \right] + c_{cd} \left[ 1 - S_{wi} - S_{wb} \right] + b_j \times (S_{wb}^{cut-off} - S_{wb}),$$

$$P_{ci} = \frac{c_{ci}}{S_{wi} - S_{wb}} \left[ 1 - S_{wi} - S_{wb} \right] + c_{ci} \left[ 1 - S_{wi} - S_{wb} \right] + b_j \times (S_{wb}^{cut-off} - S_{wb}),$$

where $b_j$ is zero for water saturation higher than $S_{wb}^{cut-off}$ and $b_j$ is zero for water saturation lower than $S_{wb}^{cut-off}$; $c_{cd}$ and $c_{ci}$ are fitting parameters used to fit experimental data. The fitting parameters used in the imbibition capillary pressure equations are constrained to keep the first point on the imbibition curves the same as obtained from the bounding primary drainage. The formulae are an extension of the power-law form first introduced by Brooks and Corey (1966) (first term) and then extended by Skjaeveland et al. (1998) (second term) for mixed-wet reservoir rocks. We introduce the third term in the equations to describe different shapes of capillary pressure curves (e.g., for bimodal pore-size distributions) because the first two terms alone could not match the experimental data, particularly for cases of dual porosity or with a wide range of pore-size distribution, and for most of the measured imbibition $P_{ci}$ curves. This capillary pressure function offers flexibility for generating a wide range of curves of different shapes, and it honors experimental data (e.g., in the asymptotic values relating to irreducible saturation and threshold capillary pressure). In addition, the same $S_{wb}$ and $S_{wi}$ can be used in both the capillary pressure function and the relative permeability function, ensuring consistency.

The scanning imbibition capillary pressure curves are generated with the following equations:

$$P_{ci} = \frac{c_{ci}(S_{wi})}{S_{wi} - S_{wb}} \left[ 1 - S_{wi} - S_{wb}(S_{wi}) \right] + c_{ci}(S_{wi}) \left[ 1 - S_{wi} - S_{wb}(S_{wi}) \right] + b_j(S_{wi}) \left[ S_{wb}^{cut-off} - S_{wb} \right],$$

where

$$c_{ci}(S_{wi}) = c_{wi} + c_{wi} \times \left[ 1 - S_{wi} - S_{wb} \right]$$

$$a_{ci}(S_{wi}) = a_{wi} + a_{wi} \times \left[ 1 - S_{wi} - S_{wb} \right]$$

$$c_{ci}(S_{wi}) = c_{wi} + c_{wi} \times \left[ 1 - S_{wi} - S_{wb} \right]$$

$$a_{ci}(S_{wi}) = a_{wi} + a_{wi} \times \left[ 1 - S_{wi} - S_{wb} \right]$$

$$b_j(S_{wi}) = b_j + b_j \times \left[ 1 - S_{wi} - S_{wb} \right].$$ .......................... (13)

In the examples shown in this paper, only two extra parameters are needed to describe the scanning curves ($a_{wi}$ and $c_{wi}$), while the three other parameters ($a_{wi1}$ and $b_{j1}$) are zero, as listed in Table 1. The secondary capillary pressure drainage scanning curves also can be generated with similar equations; however, in this paper the focus will be on imbibition scanning curves. For bounding imbibition curves, $S_{wi}$ is equal to connate water, while for other scanning curves, it denotes the saturation reversal point on the primary-drainage curve. The imbibition scanning curves originate from the bounding primary-drainage curve. Therefore, the first point in the imbibition scanning curves is calculated with Eq. 10. The parameters in Eq. 13 need to be chosen so that the scanning curves are monotonously decreasing. If instead the same parameters ($a$, $b$, and $c$) are used for both imbibition bounding and scanning curves, a nonphysical phenomenon occurs in which the entry pressure for a scanning curve can be higher than the entry pressure for the imbibition bounding curve. These model parameters should be generated from SCAL measurements on a rock-type basis (i.e., one set of model parameters for each rock type).

As discussed earlier, during primary drainage, oil invades the large pores first. For the case in which a complete wettability reversal takes place (i.e., the rock becomes oil-wet or the advancing contact angle becomes higher than 90°), upon saturation reversal, the water starts to invade the large pores first. Therefore, the entry pressure for the imbibition scanning capillary pressure curves is determined by the characteristics of the largest pores.

### Table 1—Parameters Used to Generate Drainage and Imbibition Bounding and Scanning Curves

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Uniform Pore Size (Fig. 7a)</th>
<th>Dual Porosity (Fig. 7b)</th>
<th>$P_c$ curves in Fig. 8</th>
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</thead>
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<tr>
<td>$S_{wb}$</td>
<td>0.035</td>
<td>0.035</td>
<td>0.1</td>
</tr>
<tr>
<td>$S_{wb,max}$</td>
<td>0.08</td>
<td>0.12</td>
<td>0.15</td>
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<tr>
<td>Drainage $P_c$ curve</td>
<td>$c_{cd}$ = 6, 1.2, 8</td>
<td>$a_{cd}$ = 0.45, 0.95, 0.4</td>
<td>$c_{cd}$ = -0.1, -0.1, -0.1</td>
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<td>$S_{wb,cutoff}$</td>
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<td>1</td>
<td>1</td>
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<tr>
<td>$b_j$</td>
<td>2.5, 15</td>
<td>-4</td>
<td></td>
</tr>
<tr>
<td>Imbibition $P_c$ curve</td>
<td>$a_{ci}$ = 1.4, 0.4, 0.7</td>
<td>$c_{ci}$ = 0.05, 0.1, 0.1</td>
<td>$a_{ci}$ = 0.12, 0.5, 0.3</td>
</tr>
<tr>
<td>$S_{wb,cutoff}$</td>
<td>$c_{ci}$ = -6, -0.5, -7.5</td>
<td>$b_j$ = -2, 2, -2</td>
<td>$S_{wb,cutoff}$ = 0.035 (= $S_{wb}$)</td>
</tr>
<tr>
<td>$S^{imb}_{wb,cutoff}$</td>
<td>0.035 (= $S_{wb}$)</td>
<td>0.035 (= $S_{wb}$)</td>
<td>0.1 (= $S_{wb}$)</td>
</tr>
</tbody>
</table>

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regardless of the initial oil saturation. Hence, the entry pressure of the scanning curves cannot be higher than that of the bounding imbibition curve starting from the highest initial oil saturation. In fact, if higher initial oil saturation results in a stronger oil-wet situation (i.e., with a higher advancing contact angle), the negative entry capillary pressures for the scanning curves should decrease with decreasing initial oil saturation. To honor experimental observations, the values for $c_{ao}(S_{oi})$ become less negative, and the exponent $a_{oi}(S_{oi})$ decreases as initial oil saturation decreases. The variable $b_{oi}$ can be positive or negative, depending on the pore structure and pore-size distribution of the rock. For example, for a uniform pore-size distribution, the negative imbibition capillary pressure may become flat with very little change as a function of saturation. In this case, a negative $b_{oi}(S_{oi})$ value should be used. However, for dual porosity or samples of a wide range of pore sizes, the imbibition capillary pressure may have very small entry pressure but increases (becoming more negative) as water saturation increases (see Fig. 7). In this case, a positive $b_{oi}(S_{oi})$ is needed to capture such a trend. Fig. 7 shows both measured and model-generated $P_c$ curves for both types; the parameters used to generate the model $P_c$ curves are shown in Table 1.

To illustrate how the relative permeability and capillary pressure models work, the water and oil relative permeability and the capillary pressure bounding and scanning curves generated with Eqs. 1 through 13 are shown in Fig. 8. For generating $P_c$ scanning curves, the following experimental data are needed: the primary-drainage bounding $P_c$ curve, the imbibition bounding $P_c$ curve, the $S_{oi}/S_{ow}$ correlation, and at least one of the scanning curves measured at certain initial oil saturation. The scanning curve is needed to calibrate the model and define the parameters in Eq. 13.

**Mechanistic Modeling To Investigate Transition-Zone Recovery**

Sector mechanistic models covering capillary transition zones were constructed to evaluate the impact of the relative permeability and capillary pressure characteristics on recovery performance. In this section, we first discuss the proper implementation of drainage and imbibition capillary pressure curves for the initialization of the static and dynamic modeling of capillary transition zones. We then assess the impact of relative permeability and imbibition capillary pressure bounding and scanning curves, the initial and residual oil saturation relationship, and permeability heterogeneity on recovery performance.

**Simulation-Model Description.** The simulation was performed using a 3D model of 27 layers (50x7x27) and 50 m in total thickness. The thickness of the individual layers of the model varies between 0.5 and 3.5 m, and the grid size in the x and y directions is 10x30 m, respectively. In the simulation, a vertical injector was placed in one corner of the model, and a vertical producer was placed in the diagonally opposite corner. Initial fluid distributions were assigned to the model using drainage capillary pressure curves because it is beyond the scope of this paper to assess the impact of tilting or leakage, and the resultant imbibition, on static and dynamic modeling. An x-z cross section and different permeability profiles are shown in Fig. 9. Porosity and permeability within each layer are assumed constant. The three permeability models shown in the figure are as follows: Model Perm 1 is relatively homogeneous, with permeability varying between 1 and 10 md. Model Perm 2 has the same base permeability distribution as Perm 1, but with three high-permeability layers in the top, middle, and bottom parts of the reservoir. Model Perm 3 also has the same base permeability distribution as Perm 1, but with the high-permeability layers located at the top of the reservoir.

**Implementing Drainage and Imbibition Capillary Pressure Models in Simulation.** Here, we assume that the simulation model is initialized by the primary-drainage capillary pressure curves (i.e., no imbibition or dynamic effect caused by tilting or leakage). It was found that initializing with drainage capillary pressure, then switching to imbibition capillary pressure once production starts, may cause some instability in the model and some numerical changes in fluid saturation. This is caused by the gravity vs. cap-

**Fig. 7**—Model (lines) and measured (symbols) $P_c$ bounding curves of (a) a low-permeability sample of uniform pore-size distribution and (b) a high-permeability sample of a dual-porosity system.

**Fig. 8**—(a) Oil and water relative permeability bounding (thick lines) and scanning curves (thin lines) and (b) capillary pressure bounding (thick lines) and imbibition scanning curves (thin lines) calculated with the model presented in Eqs. 1 through 13.
illary pressure hydrostatic equilibrium condition imposed at reservoir initialization and the improper implementation of the imbibition capillary pressure model. This saturation change is nonphysical and is especially pronounced for reservoirs with vertical permeability heterogeneity and when the imbibition capillary pressure is negative (i.e., oil-wet behavior).

To explain the problem, the drainage and imbibition capillary pressure curves for two layers (high vs. low permeability) are shown in Fig. 10a. At the initialization governed by hydrostatic equilibration, the capillary pressure (oil pressure/water pressure) at the boundary between the two layers is the same; therefore, the saturation is at Point A in the low-permeability layer and at Point B in the high-permeability layer. Once production starts and after the capillary pressure is switched from primary drainage to imbibition bounding curve, the capillary pressure in the high-permeability layer will switch to Point C, and the capillary pressure in the low-permeability layer will switch to Point D. The two layers are no longer at equilibrium because the capillary pressures at Points C and D are not the same. Therefore, the saturations in both layers start to change to reach the new equilibrium governed by the gravity vs. imbibition capillary pressure balance. The saturation change stops at Point E in the low-permeability layer and Point F in the high-permeability layer (i.e., the oil saturation increases in the low-permeability layer and decreases in the high-permeability layer). This change in fluid saturation is a modeling artifact caused by the switch from drainage bounding curve to imbibition bounding curve at timestep zero. The picture changes once the capillary pressure scanning curves, as observed from SCAL experiments (shown in Fig. 10b), are correctly implemented in the simulation. Instead of switching from the primary drainage to the imbibition bounding curve, once waterflooding starts, the capillary pressures in both layers follow their respective scanning curves. As a consequence (see Fig. 10b), the capillary pressures start at the same points as on the primary drainage and will only change along the imbibition scanning curves once water saturation is increasing. In this case, water saturation shows the expected trend, and no capillary crossflow between the different layers takes place.

Impact of Initial Oil Saturation. As discussed previously, oil recovery from the transition zone is dependent on the initial-oil-saturation distribution. This is illustrated in Fig. 11 for a homogeneous model using two different capillary pressure models for initialization, as shown in Fig. 12. As expected, higher initial water saturation shows relatively higher water cut. Therefore, special attention needs to be paid to accurately calculate the initial fluid distribution in the transition zone. The following factors need to be taken into account in calculating initial saturation distribution: FWL, IFT of reservoir fluids, wettability, drainage vs. imbibition processes, and geological heterogeneities. Uncertainty in

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**Fig. 9**—(a) x-z cross section and (b) three different permeability profiles labeled as Perm 1, Perm 2, and Perm 3; see text for explanation.

**Fig. 10**—Drainage bounding curves used for initialization, while in (a), only imbibition bounding curves are used, and (b) bounding and scanning imbibition $P_c$ curves are used once waterflooding starts. No jump in saturation occurs when scanning curves are used.

**Fig. 11**—Oil rate and water cut (BSW) as a function of injected PV for two different saturation height functions (SHF); thin lines for high initial water saturation and thick lines for low initial water saturation (see Fig. 12).
these basic parameters may have as significant an impact on field performance as details of the relative permeability model or the $S_{or}/S_{or}$ correlation.

**Impact of Relative Permeability Scanning Curves.** To evaluate the impact of using different relative permeability models in assessing waterflood recovery performance from a capillary transition zone, two different scenarios are run:

- **Scenario 1:** relative permeability imbibition bounding curves alone.

- **Scenario 2:** relative permeability imbibition scanning curves and $S_{or}/S_{or}$ correlation.

In both scenarios, all the basic rock and fluid properties (porosity, permeability, capillary pressure, and fluid PVT) are kept the same. **Fig. 13** shows that, when using a family of relative permeability scanning curves in simulating the waterflood recovery, the recovery factor (RF) increases by more than 10 saturation units for the same number of PV of water injection. As expected, the difference in the RFs between the bounding relative permeability model and the physically correct relative permeability model consisting of scanning curves is dependent on the initial-oil-saturation distribution in the transition zone. For example, for the interval relatively high in the transition zone in which initial oil saturation is high, the waterflood RF becomes less sensitive to scanning curves, whereas for the interval low in the transition zone with low initial oil saturation, the waterflood RF becomes strongly dependent on the assignment of relative permeability scanning curves.

**Impact of Different Oil Relative Permeability Scanning Curves and $S_{or}/S_{or}$ Relations.** As shown in the previous section, using relative permeability scanning curves in modeling the capillary transition zone has a significant impact on oil-recovery predictions. In this section, we compare different scanning curves and $S_{or}/S_{or}$ models for a range of reservoir heterogeneities. The parameters used to generate the different scanning curves are shown in **Table 2**. In total, 15 different scenarios were run: one with no scanning curves, plus seven different scanning curves for two different permeability-profile models, where one is relatively homogeneous and the other is heterogeneous (i.e., permeability profile Models 1 and 2; see **Fig. 9**). The different scanning models are generated by changing the maximum residual oil saturation ($S_{or}^{max}$), $S_{or}/S_{or}$ correlations, and drainage and imbibition bounding curves. Running these different scenarios serves two objectives:

- To quantify the impact of each model parameter on recovery performance for both homogeneous and heterogeneous reservoirs.

- To help design an SCAL program for the transition zone (i.e., because SCAL programs for the transition zone can be very expensive and time-consuming, by conducting the mechanistic modeling, the SCAL program can be guided to focus on the parameters that have the most impact).

**Figs. 13 and 14** compare the relative permeability model with scanning curves to the base model with bounding curves alone for both permeability profiles Perm 1 and Perm 2. The figures show that implementing scanning curves has a much higher impact for the heterogeneous model on both RF and water cut compared with the homogeneous model.

**Figs. 15 and 16** compare four different scanning models for the homogeneous and heterogeneous permeability profiles, respectively. The scanning models have the same Corey exponent and the same endpoints $[k_{or}(S_{or})]$, but two different $S_{or}^{max}$ (10% and 20%) and two different $S_{or}/S_{or}$ correlations (linear and linear with a plateau; Land’s $S_{or}/S_{or}$ correlation falls between the two models). The results show that

- $S_{or}^{max}$ and $S_{or}/S_{or}$ correlations are important for both permeability models.

- The main impact is caused by $S_{or}^{max}$, when comparing the same $S_{or}/S_{or}$ model but different $S_{or}^{max}$.

As $S_{or}^{max}$ decreases, the $S_{or}/S_{or}$ model becomes less important. In this case, the SCAL program should focus on measuring $S_{or}^{max}$ instead of $S_{or}/S_{or}$ correlations.

**Figs. 17 and 18** compare four different scanning models for the homogeneous and heterogeneous permeability profiles, respectively. Here, the focus is on evaluating the impact of the shape of scanning curves with fixed $S_{or}^{max}$, $S_{or}/S_{or}$, and $S_{or}/S_{or}$ correlations. The

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**TABLE 2—PARAMETERS USED TO GENERATE THE OIL AND WATER RELATIVE PERMEABILITY CURVES**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Perm 1</th>
<th>Perm 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k_{or}$</td>
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<td>0.7</td>
</tr>
<tr>
<td>$n_{or}$</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>$k_{or}$</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>$n_{or}$</td>
<td>3.5</td>
<td>3.5</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>0.003</td>
<td>0.003</td>
</tr>
<tr>
<td>$S_{or}$</td>
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<td>1.5</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>$S_{or}$</td>
<td>Eq. 1</td>
<td>Eq. 1</td>
</tr>
</tbody>
</table>

*The oil drainage Corey value ($n_{or}$) is used to generate the drainage bounding curve.

**Base model** refers to the case in which we used the bounding imbibition curve alone, with no scanning curves.
four models are generated with different oil endpoints \([k_{\text{ro}}(S_{\text{oi}})]\), except at the maximum \(S_{\text{oi}}\) and different imbibition bounding curves (with oil Corey exponents of 3 and 4, respectively), but the same \(S_{\text{ori}}^{\text{max}}\) (10%) and the same \(S_{\text{oi}}/S_{\text{or}}\) model (linear model). Figs. 17 and 18 show that the oil endpoints, when using the same \([k_{\text{ro}}(S_{\text{oi}})]\), have very little impact within the saturation range investigated especially for the homogeneous reservoir model. These results suggest, therefore, that using the primary-drainage oil relative permeability curve from which all scanning curves originate is an acceptable approach.

On the basis of the simulation sensitivity runs, it is clear that implementing oil relative permeability scanning curves has the most significant impact on transition-zone recovery. Both \(S_{\text{or}}\) and \(S_{\text{oi}}/S_{\text{or}}\) correlations have an important impact on recovery; however, more importance is attributed to \(S_{\text{ori}}^{\text{max}}\). When \(S_{\text{ori}}^{\text{max}}\) becomes low (e.g., less than 10%), the shape of the \(S_{\text{or}}/S_{\text{or}}\) correlation becomes less important. Once the imbibition bounding curve and the \(S_{\text{or}}/S_{\text{or}}\) correlation are properly measured in SCAL, the details of the scanning curves (i.e., oil endpoints and Corey shape) are of less importance for the cases studied. The basic SCAL program should focus on imbibition bounding curves, \(S_{\text{ori}}^{\text{max}}\), and \(S_{\text{or}}/S_{\text{or}}\) correlations. Once these have been measured, scanning curves can be generated with the models presented in Eqs. 1 through 9. It is recommended to conduct similar mechanistic simulations for specific field cases to be investigated before starting any extensive SCAL program.

**Impact of Water Relative Permeability.** Water relative permeability, especially for the transition zone, is usually the most uncertain parameter. Therefore, it is important to assess the impact of water relative permeability uncertainty. One reason for the relative lack of reliable imbibition water relative permeability compared to oil is the experimental limitation inherent in the centrifuge technique, which can only measure the relative permeability of the displaced phase (i.e., oil-phase relative permeability in a water-displacing-oil experiment). A combination of centrifuge and steady-state measurements with carefully designed experimental procedures is needed to define the water relative permeability bounding/scanning curves. A total of 12 simulation runs was performed for two different permeability profiles (homogeneous and heterogeneous), three different water Corey exponents (2.5, 3.5, and 4.5), and two different water permeability endpoints \(k_{\text{rw}}(S_{\text{ori}}^{\text{max}})\), 0.3 and 0.6; see Table 3. The results of the simulation sensitivity runs performed on the heterogeneous permeability profile are shown in Fig. 19. The results of the homogeneous permeability profile showed hardly any difference on both recovery and water cut. For the heterogeneous permeability profile (Fig. 19), the impact of the water relative permeability is more significant on the RF. For heterogeneous reservoirs, high water mobility in the high-permeability layers will result in early water breakthrough, leaving oil unswept in the low-permeability layers. The results also show that the water Corey exponent is of less importance compared to the water relative permeability endpoint. Therefore, for the cases assessed, quantifying the endpoints for water relative permeability \([k_{\text{rw}}(S_{\text{ori}}^{\text{max}}), S_{\text{ori}}, S_{\text{or}}]\) is more important for dynamic modeling of transition zones than extensively measuring the water Corey exponent (hence the shape of the relative permeability curves).

**Impact of Geological Heterogeneity.** To evaluate the impact of geological heterogeneity on transition-zone recovery, three different geological models have been constructed:

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**Fig. 16**—Recovery factor and water cut (BSW) for four relative permeability models shown in Table 2—Hyst1 (solid line with triangle), Hyst3 (dashed lines), Hyst4 (solid lines), and Hyst5 (dotted line)—for Perm 2.

**Fig. 17**—Recovery factor and water cut (BSW) for four relative permeability models shown in Table 2—Hyst1 (solid line with triangle), Hyst6 (dashed lines), Hyst7 (solid lines), and Hyst8 (dotted line)—for Perm 1.

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Scenario 1: homogeneous model with low permeability (Perm 1 in Fig. 9).
Scenario 2: high-permeability streaks distributed randomly in the reservoir (Perm 2 in Fig. 9).
Scenario 3: high-permeability streaks in the upper part of the reservoir (Perm 3 in Fig. 9).

These three models are assumed to have the same input properties, including relative permeability models and $S_w/S_o$ correlations, for the same permeability class. However, the capillary pressure model is dependent on permeability, so the high-permeability layers have negative capillary pressures with lower entry pressures.

As shown in Fig. 20, the RF and water cut are strongly dependent on the geological heterogeneity. The homogeneous model has the highest recovery after the 1.5 PV injected, though it takes the longest time for the same number of PV of injection because of the low permeability. The heterogeneous model shows poorer oil recovery owing to the bypassing of low-permeability layers (Masalmeh et al. 2003). The homogeneous model starts with low water cut (<5%), which increases steeply at 0.4 PV. However, the two heterogeneous models start with zero water cut, which then increases steeply at 0.07 and 0.2 PV for the Perm 2 and Perm 3 models, respectively.

**Impact of Capillary Pressure Models.** The impact of different capillary pressure models on oil recovery from the transition zone is evaluated for three different permeability profiles, as used in the previous section. In total, 16 different runs are performed; for each permeability profile, four different capillary pressure models are used. The four different capillary pressure models are:

1. $P_{c\_model1}$: drainage capillary pressure used for both initialization and waterflooding;
2. $P_{c\_model2}$: drainage capillary pressure used for initialization; then, zero capillary pressure used once waterflooding starts;
3. $P_{c\_model3}$: drainage capillary pressure used for initialization; then, the imbibition bounding $P_{c}$ curve is used once waterflooding starts; and
4. $P_{c\_model4}$: correct implementation of the capillary pressure model (Eqs. 10 through 13) with both drainage and imbibition, including bounding and scanning curves.

The results of the runs performed on permeability profile Perm 2 (see Fig. 9) are shown in Fig. 21. For the homogeneous permeability model (Perm 1), the capillary pressure has very little impact on total recovery, and the RF changes by less than 5% for the four different $P_{c}$ models. In contrast, for the heterogeneous models (Fig. 21), the capillary pressure modeling has a significant impact on both the RF and the water cut. This point was discussed in detail in Masalmeh et al. (2003), where it was shown that for mixed/oil-wet heterogeneous reservoirs, imbibition capillary pressure is probably the most important parameter that affects waterflooding. It can behave as a barrier, preventing crossflow between the different layers and resulting in poor sweep efficiency. For the transition zone, the imbibition scanning curves play an important role, improving crossflow between the high- and low-permeability layers. This results in better recovery and postpones water breakthrough when compared to the case of using the bounding imbibition curve alone. There is also a significant difference between the two heterogeneous models (Perm 2 and Perm 3). Therefore, recovery is strongly dependent on the details of the geological heterogeneity and the capillary pressure models. Preserving both low- and high-permeability layers in the reservoir model has a significant impact on the reservoir-performance predictions because it controls gravity/capillary crossflow and channeling of injected water. Production performance and recovery will differ for various input assumptions of wettability, shapes of saturation functions, and vertical permeability profiles.

### Table 3—Parameters Used to Generate the Different Water Relative Permeability Curves

<table>
<thead>
<tr>
<th>$k_{rw_max}$</th>
<th>$n_{rw}$</th>
<th>$S_{w_max}$</th>
<th>$S_{o_max}$</th>
<th>$S_{w}/S_{o}$</th>
<th>$P_{c_model}$ model</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
<td>0.6</td>
<td>0.6</td>
<td>Eq. 1</td>
</tr>
<tr>
<td>3.5</td>
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<td>4.5</td>
<td>3.5</td>
<td>2.5</td>
<td>Eq. 1</td>
</tr>
</tbody>
</table>

*Oil relative permeability bounding and scanning curves are generated with the model Hyst1 from Table 2.*
Impact of Transition-Zone Modeling on Remaining Oil Distribution. So far, the discussion has focused on oil recovery and water cut. However, it is also important to map the fluid distribution in the reservoir at the end of the waterflood for the different scenarios discussed because the remaining oil distribution will significantly impact any future improved-oil-recovery (IOR) or enhanced-oil-recovery (EOR) options. For example, to answer the question of whether we should target the remaining oil saturation either by infill drilling or by an EOR process, it is necessary to know the fluid distribution at the end of waterflooding.

The impact of using relative permeability scanning curves on fluid distribution at the end of the waterflood for permeability profiles Perm 2 and Perm 3 is shown in Fig. 22. This figure shows saturation logs (saturation vs. depth) at a distance of 250 m from the injector after 1.4 PV injected for the cases of using scanning curves (referred to as “Hyst”) and no scanning curves (referred to as the “Base Model”). In both cases, the initial saturation profile ($S_w$) is the same. The figure demonstrates that the use of relative permeability scanning curves has a significant impact not only on recovery but also on distribution of the remaining oil saturation. When scanning curves are used, more crossflow between the different layers takes place, which results in a more-uniform saturation profile and a better sweep. The proper use of capillary pressure on fluid distribution and sweep efficiency was discussed in Masalmeh et al. (2003), where it was demonstrated that for heterogeneous reservoirs, capillary pressure is very important and may act as a barrier, preventing crossflow between the different layers (which leads to poor sweep efficiency).

Field Cases

The results of the above mechanistic modeling show the key factors that control production performance from a transition zone. Transition zones may produce almost-dry oil, and in other cases, they may cut significant water from Day 1, depending on the initial oil saturation, heterogeneity, relative permeability, and capillary pressure hysteresis. Therefore, field-development planning needs to take into account these different factors in an integrated manner. It has been reported in the literature (Parker and Rudd 2000) that transition zones have produced dry oil (sometimes for even a few years), while reservoir-simulation results indicated much earlier water breakthrough. However, lower-than-expected recoveries also have been reported from transition zones elsewhere. To explain dry-oil production from the transition zone, some authors (Parker and Rudd 2000) suggested the use of a pseudorelative permeability model with a high immobile-water saturation (50% or so), which is not supported by logs or core data. Because of the nonphysical nature, this approach may lead to a history match but gives a rather poor prediction of future production performance and unrealistic remaining-oil distribution. The higher-than-expected oil production from transition zones can be explained with the transition-zone relative permeability model presented in this paper.

The transition-zone model and methodology presented in this paper were used to match field data and explain why the transition zone can produce more oil than predicted by the original models. Here, we present two field cases in which most of the STOIP is in the transition zone.
Oil relative permeability scanning curves have been generated at different initial oil saturations. In Case 1, we first tested the relative permeability models against the well-test production data (1 month) of a well in the carbonate reservoir from which a suite of core samples has been obtained for SCAL experiments. The well was situated in the transition zone. The relative permeability models with the bounding and scanning curves and \( S_{or}/S_{oi} \) relations described in this paper (Eqs. 1 through 9) have been implemented in a simulation model using the Shell in-house reservoir simulator (MoReS). The simulated oil-production rate and the water cut show a very close match with the overall field data (Fig. 23). It is important to note, however, that at this early stage of the well test, the production performance is sensitive only to the portion of the relative permeability curves that is relevant to the initial saturation range in the transition zone. Later in the field life, as the field water saturation changes, the full relative permeability curves become more important. The impact of the experimentally measured relative permeability curves and corresponding residual oil saturations on recovery efficiency has been quantified with the simulation model. The model consists of five different layers in the \( z \)-direction, each 35 m in total thickness, 400 m in width, and 1200 m in length. Two horizontal injectors and one horizontal producer are positioned in the model. Fig. 24 shows the results of two different simulation runs. The first run was performed with a single set of relative permeability curves (i.e., bounding curves alone) to characterize the entire field independent of initial oil saturation. The relative permeability curves were measured at the highest initial oil saturation, as in any conventional SCAL program. The second simulation run was performed with the measured \( S_{or} \)-dependent relative permeability curves. Fig. 24 shows that the RF has increased from 32 to 56% when using \( S_{or} \)-dependent relative permeability curves. The water cut at abandonment was taken at 95%.

Fig. 25 shows a history match of water cut for three different wells in a transition zone for a second carbonate field. The three wells show different water-cut trends. For the crestal well, the water cut increases gently with time, while the two flank wells show a steep increase in the water cut. The different behavior of the three wells positioned at different heights above the FWL in the transition zone agrees with the results of the simulation using the relative permeability model presented in this paper (Eqs. 1 through 9). The question of whether wells should be completed in the transition zone depends on a number of technical and economic factors, and a detailed mechanistic modeling should be performed to decide on the best development options and the expected water cut and recovery against time.

Conclusions

1. A relative permeability and capillary pressure model consisting of bounding and scanning curves and an initial-residual-oil relationship has been developed for the dynamic modeling of capillary transition zones, especially for carbonate fields. This model and modeling methodology are based on extensive laboratory measurements, as well as detailed mechanistic modeling, to capture the key underlying physics of rock/fluid interactions in transition zones.

2. The understanding and prediction of transition-zone oil recovery need to start from an accurate static modeling to characterize the geological heterogeneities and petrophysical properties that influence the initial saturation distributions. Saturation-height functions derived from logs and drainage capillary pressure curves should be reconciled, taking into proper account wettability and its influence on the resistivity-index-vs.-saturation relationship (i.e., saturation exponent) through the transition zone.

3. If there is field evidence to suggest possible movement of the FWL after oil migration, then the usual assumption of a drainage process to initialize reservoirs becomes invalid, and both drainage and imbibition capillary pressure and resistivity index may be needed to determine the initial saturation distribution in the field, including the transition zone.

4. The initial-residual-oil (\( S_{or}/S_{oi} \)) correlation is strongly dependent on wettability and pore structure and pore-size distributions. Land’s correlation may not be valid for oil-wet carbonates because it was derived on the basis of a water-wet assumption. Experimental measurements using representative rock/fluid systems are recommended to establish this correlation.

5. In capillary transition zones of carbonate reservoirs, the water-wet assumption can result in errors in residual oil saturation and relative permeability and capillary pressure bounding and scanning curves.

6. Specially designed laboratory measurements are needed to characterize the static and dynamic behavior of capillary transi-
tion zones and calibrate the dynamic models described in this paper. This requires a strategy of core/log integration to capture the geological heterogeneities, the establishment of field-representative initial water saturations through the transition zones, wettability restoration/preservation at representative initial water saturations, and a combination of SCAL experiments to measure relative permeability and capillary pressure bounding and scanning curves.

7. The proposed relative permeability and capillary pressure models for transition zones have been implemented in an in-house reservoir simulator (MoReS) to allow the history match and production forecast of reservoirs containing significant capillary transition zones. Close agreement has been obtained between simulation-model predictions and actual field/well performances, demonstrating the benefits of improved characterization and modeling of capillary transition zones in reducing uncertainties significantly and aiding field-development planning.

Nomenclature

\[ a_{wp}, a_{wir}, a_{oil}, a_{w}, b_{p} = \text{fitting parameters in relative permeability and capillary pressure models} \]

\[ k_{r} = \text{relative permeability of phase j} \]

\[ n_{d} = \text{drainage Corey exponent for phase j} \]

\[ n_{i} = \text{imbibition Corey exponent for phase j} \]

\[ P_{d} = \text{drainage capillary pressure} \]

\[ P_{i} = \text{imbibition capillary pressure} \]

\[ S_{oi} = \text{initial oil saturation} \]

\[ S_{im} = \text{maximum initial oil saturation above which there is no dependency of } S_{oi}/S_{or} \]

\[ S_{or} = \text{residual oil saturation} \]

\[ S_{wor} = \text{maximum residual oil saturation} \]

\[ S_{cw} = \text{connate water saturation} \]

\[ S_{sw} = \text{mathematical point to initialize water imbibition scanning } k_{rw} \]

Subscripts

\[ d = \text{drainage} \]

\[ i = \text{imbition or initial} \]

\[ o = \text{oil} \]

\[ r = \text{residual or relative} \]

\[ w = \text{water} \]

Superscripts

\[ d = \text{drainage} \]

\[ imb = \text{imbition} \]

Acknowledgments

We would like to acknowledge the contributions from our colleagues in the Shell E&P Technology Centre in Rijswijk, The Netherlands, particularly Sjaam Oedai, for the careful experimental SCAL measurements. We are also grateful for the support and encouragement of Shell Abu Dhabi management.

References


**SI Metric Conversion Factors**

- \( \text{ft} \times 3.048 \times 10^{-1} = \text{m} \)
- \( \text{ft}^3 \times 2.831685 \times 10^{-2} = \text{m}^3 \)
- \( \text{psi} \times 6.894757 \times 10^2 = \text{kPa} \)

*Conversion factor is exact.

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S.K. Masalmeh is currently a senior EOR reservoir engineer working with Shell Technology Oman (STO), a Shell EOR R&D center in Muscat, Oman. Previously, he worked for Shell Abu Dhabi as a senior reservoir engineer and Shell EP Technology Centre in Rijswijk, The Netherlands, as a research scientist. Masalmeh has published more than 20 technical articles on flow in porous media, SCAL, and EOR. He holds a BSc degree in physics from Birzeit U., Palestine, an MSc degree in atomic physics from the U. of Amsterdam, and a PhD degree in laser physics from Leiden U.

I. Abu Shiekah is currently a reservoir engineer working in the Qarn Alam Planning and Development team of Petroleum Development Oman (PDO). Previously, he worked with the SCAL and carbonate field studies teams in the Shell EP Technology Centre in Rijswijk as a research reservoir engineer. Abu Shiekah has published a number of papers in experimental physics, flow in porous media, and SCAL. He holds a BSc degree in physics from Birzeit U., Palestine, and a PhD degree in experimental physics from Leiden U.

X.D. Jing is currently Manager and Principal Reservoir Engineer at Shell Technology Oman (STO) in Muscat. Previously, he worked with Shell EP Technology Centre in Rijswijk, The Netherlands; Shell/SQU Carbonate Centre in Muscat; BG Group in Reading, U.K.; and Core Laboratories Advanced Technology Centre in Aberdeen. Jing served on the petroleum engineering faculty at Imperial College, London, from 1994 to 2001 and is currently a visiting professor there. He holds a BSc degree from East China Petroleum Inst. and PhD and DIC degrees from Imperial College, London, all in petroleum engineering. Jing is a Technical Editor for SPE and a past president of the Soc. of Core Analysts.