APPLICATIONS OF THE INTERCEPT METHOD TO CORRECT STEADY-STATE RELATIVE PERMEABILITY FOR CAPILLARY END-EFFECTS

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in St. John's Newfoundland and Labrador, *Canada, 16-21 August, 2015*

ABSTRACT

During coreflood tests in the laboratory to determine relative permeability, capillary discontinuities at sample ends influence fluid flow and retention. When this influence or end-effect artifact is appreciable, the laboratory data incorrectly models the reservoir-condition scenario, which may result in serious errors in reservoir performance predictions. The end effect artifact is a well-known problem with unsteady-state test data. It is also an issue with steady-state data; it is typically handled by increasing sample length or experiment flow rates. Increasing sample length by arranging a series of core plugs to create a long composite is not a perfect fix to the end-effect issue, because end-effects can still exist between core plugs as well as at the end of the composite. Increasing flow rate may not be possible for gas-liquid or gas-condensate tests in which the experimentalist limits pressure drop because of mass transfer considerations.

The "Intercept Method" is a modified steady-state approach that corrects data for end-effect artifacts while conducting the test. Corrections are determined from simple calculations based on multiple rates versus pressure drop measurements at each test fractional flow condition. Application of the method does not depend upon a-priori characterization of capillary pressure versus saturation. This work focuses on the application of the Intercept Method and demonstrates lab examples of gas-liquid, gas-condensate and liquid-liquid systems in which end-effect errors induce the artifact of flow rate dependence in relative permeability measurements. However, after applying the Intercept Method on the same data, the rate-dependent family of curves collapse into a set of unique, flow rate independent, end-effect corrected curves. Along with end-effect correction, the method also simultaneously corrects errors from capillary discontinuities between core plug faces in a composite and pressure transducer zero-errors. The workflow of the method is explained and demonstrated through several lab test examples.

INTRODUCTION

The steady-state relative permeability method consists of co-injecting fluids in steps of increasing or decreasing fractional flow, allowing sufficient time at each step to establish equilibrium before recording data. Pressure and saturation data at steady-state conditions are used to generate relative permeability versus saturation curves for each fluid phase.

Capillary end-effects (CEE) yield pressure drop and saturation artifacts that cause errors in laboratory-measured steady-state relative permeability functions [1, 2]. Deviations of relative permeability with rate have been observed only where boundary effects are known to exist, and disappear as the boundary effect vanishes [2, 3]

The end-effect decreases as the length of the flooded system, rate of injection, or fluid viscosities are increased [4, 5]. However, the end effect can occur in the individual segments of a long composite core [1, 6] due to capillary discontinuities. Performing high injection rate or pressure drop tests might not be possible in many cases due to phase behavior (e.g., gas-condensate) or rock reactivity (e.g. clay-rich cores) considerations [1]. High pressure drop can yield problematic gas compressibility effects, phase behavior changes in gas-condensate tests, and fines migration issues in a clay-rich rock. For laboratory tests on tight rocks, pressure drops high enough to mask end-effects may be impractical to attain without causing other experimental artifacts.

Numerical approaches to correct relative permeability data for capillary end-effects are often complex and require additional information [7] (in-situ saturations, independent measures of capillary pressure versus saturation functions), and might not provide unique solutions. Another end-effect correction approach is to use internal pressure taps in combination with in-situ saturation monitoring [3], Using internal pressure taps is challenging for reservoir condition tests in which core is jacketed with metal foil to prevent gas permeation through the core sleeve. Also, additional pressure taps do not guarantee to eliminate end-effect errors between core plugs in stacked composites.

A plot of pressure drop (ΔP) versus flow rate (Q) is frequently used as a diagnostic in routine and special core analyses. If the data is linear but the intercept is not zero (Figure1a), the experimentalist may interpret that the offset is the result of a transducer zero shift or gravity head. When the data is subsequently “corrected” for the offset (Figure 1b), each measurement yields the same permeability. If an offset correction is not applied, a different permeability is calculated from each measurement (Figure 1c) and it will seem that permeability depends upon flow rate.

We have found in multiphase steady-state lab tests that when the length over which ΔP is measured is the entire length of the sample, capillary end-effects cause a positive or negative ΔP intercept shift similar to the illustration of Figure 1a. The effect is easy to identify when multiple rates are tested at each steady-state flow ratio or fractional flow condition. A simple saturation correction is also easily determined and applied. This work is a companion to a previous publication[1] that focused on descriptions of background, theory, and simulation followed by brief examples from two gas-condensate systems. The focus of this work is from an experimentalist perspective, with brief description of the method followed by examples of its use in gas-condensate, gas-water, and oil-water systems using published and in-house data.

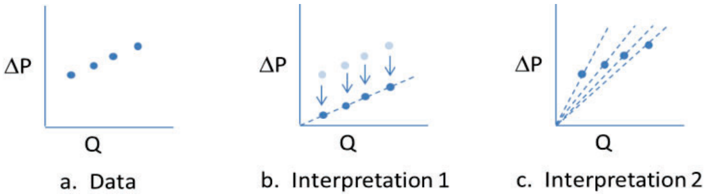


Figure 1: Conceptual relationships between pressure drop and rate for different flow scenarios.

CONCEPT

The capillary end-effect (CEE) results from a capillary discontinuity at the core outlet that causes accumulation of one phase relative to the other. Figure 2 is a schematic of water saturation in a water-oil steady-state coreflood test. In the figure, saturations are Sw_{CEE}, average water saturation in the CEE region; $Sw_{Measured}$, average measured water saturation; and Sw_{True}, water saturation in the non-CEE region. The CEE region, which develops because of the capillary discontinuity at the outlet end of the sample, influences both pressure drop and saturation measurements in a steady-state coreflood test. When a CEE artifact is appreciable, the laboratory data incorrectly models the reservoir scenario, which may result in erroneous reservoir performance predictions. Hence, it is important to estimate and correct CEE-related errors in lab tests.

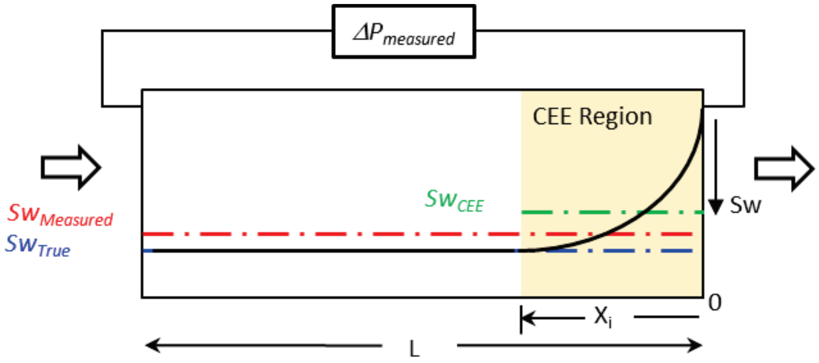


Figure 2: Schematic of water saturation in an oil-water steady-state coreflood[1], where $Sw_{Measured}$ = core average saturation, Sw_{CEE} = average saturation inside CEE region, and Sw_{True}= saturation outside CEE region.

The Intercept Method corrects CEE errors from both pressure and saturation measurements for each fractional flow condition during a steady-state coreflood test. Gupta and Maloney have described the theory in detail [1]. In a conventional steady-state relative permeability test, phases are co-injected with increasing or decreasing fractional flow, with a steady-state condition achieved at each fractional flow. For the Intercept Method, in addition to the conventional approach, the steady-state condition is achieved at multiple flow rates at each fractional flow. Trends in pressure drop and saturation versus rate are used to correct the data set for the capillary end effect at the current fractional flow. The corrected pressure and saturation data are subsequently used to calculate CEE-corrected relative permeability curves using Darcy’s law.

Pressure Correction

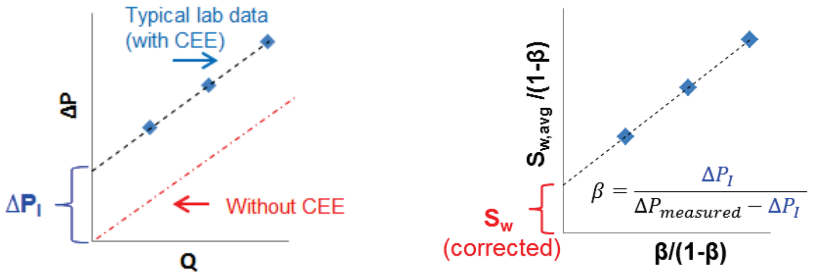
The measured pressure drop across the core ($\Delta P_{measured}$) is the sum of the theoretical pressure drop ($\Delta P_{Corrected}$) which would occur if there were no CEE in the core plus the pressure drop resulting from the CEE (ΔP_{CEE}). Gupta and Maloney[1] demonstrated through analytical calculations that the ΔP_{CEE} is independent of the total flow rate (for Stokes flow or Darcy flow) for a given fractional flow (assuming CEE region is smaller than the core length) in a steady-state coreflood test. For the Intercept Method application, steady-state pressure drop versus total flow rate is plotted for a given fractional flow. The plot normally has a linear trend with a non-zero intercept (ΔP_I). This linear trend between $\Delta P_{measured}$ and total flow rate has been observed in lab tests discussed later in this paper and previous work [1]. Based on the above discussion, ΔP_I is equal to ΔP_{CEE}, assuming $\Delta P_{measured}$ are corrected for gauge zero offset. If a pressure gauge offset exists, then ΔP_I will equal ΔP_{CEE} plus the offset error. The offset error can be determined at the beginning or end of the test and can be discounted from ΔP_I to get the true ΔP_{CEE} value for each fractional flow. The CEE-corrected pressure drop is the difference of the measured pressure drop across the core ($\Delta P_{measured}$) and the intercept (Figure 3a).

$$\Delta P_{Corrected} = \Delta P_{measured} - \Delta P_I \qquad (1)$$

Figure 4 is a schematic of phase pressures inside a composite at a steady state condition for a typical oil-water coreflood. CEE results in additional positive pressure drop resistance to one phase and a reduced resistance to the other. However, the CEE-corrected pressure drop of each phase is the same. The CEE-corrected phase pressures differ by a constant value equivalent to capillary pressure at CEE-corrected saturation (Sw_{True}). Hence, the Intercept Method can be applied using an apparatus in which pressure drop is measured for one phase instead of both phases.

Saturation Correction

Gupta and Maloney [1] demonstrated that the average saturation in the CEE region is independent of the total flow rate for a given fraction flow. They derived that the CEE-corrected saturation (Sw_{True}) for a given fractional flow is the intercept of the plot of $Sw_{avg}/(1-\beta)$ [y-axis] and $\beta/(1-\beta)$ [x-axis], where β is $\Delta P_I/\Delta P_{Corrected}$ and Sw_{avg} is the average saturation in the core (Figure 3b). The derivation assumes that drop measurements across the core are corrected for gauge zero offset. The Intercept Method corrects not only the capillary discontinuity at the core outlet end, but also the capillary discontinuities between the plug junctions in a composite when multiple core plugs are stacked in series (Figure 5). The additional pressure resistance from capillary discontinuities (inside and at the end) is reflected in the intercept (ΔP_I) of the pressure correction plot (Figure 3a). Subtracting the intercept (ΔP_I) from the lab measured pressure drop across the composite gives the CEE-corrected pressure drop.



(a) (b)

Figure 3: Schematic plots used during the Intercept Method application, (a) pressure drop versus total flow rate plot, where CEE-corrected pressure drop is the difference between the lab-measured pressure drop across the core and the intercept, and (b) saturation plot, where intercept is the CEE-corrected saturation.

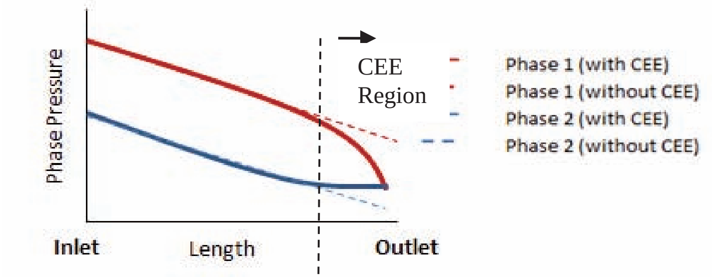


Figure 4: Schematic of phase pressures with and without CEE at steady-state condition inside a composite core.

For saturation correction, the capillary discontinuities between plugs only change the slope of the saturation correction plot (Figure 3b), but the intercept remains the same and equal to the CEE-corrected saturation. Similarly, the Intercept Method also corrects for the apparatus related errors, e.g., gauge zero errors, and from the pressure drop measurements. However, the apparatus-related pressure drop is subtracted from the intercept of pressure drop versus flowrate plot before performing saturation correction.

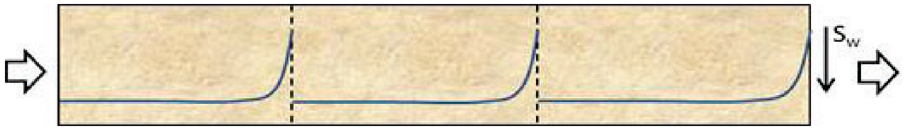


Figure 5: Schematic of water saturation in a composite core during an oil-water steady-state test with capillary discontinuities between the plugs.

METHOD APPLICATION AND DISCUSSION

The Intercept Method is applicable for liquid-liquid, gas-liquid, and gas-condensate steady-state relative permeability tests. The method provides CEE-correction for tests performed at low rates and pressure drops. Data are corrected as measured, without requiring in-situ saturation monitoring, internal pressure taps, or simulation. A common manifestation of CEE is the flowrate dependence artifact in "Stokes flow[8]" relative permeability measurements. Chen and Wood [3] demonstrated that steady-state relative permeability results were independent of test flow rates. The Intercept Method addresses the flow rate dependent artifact in measured relative permeability curves.

In a steady-state relative permeability test, application of the Intercept Method requires attaining steady-state at multiple rates for each fraction flow. A minimum of two total flow rates per fractional flow is required to apply the method; however, 3 to 4 total flow rates per fractional flow is recommended to generate high-confidence pressure and saturation correction plots (Figure 3). The time to attain additional steady-state points is very small compared to the first total flow rate for each fractional flow point. In theory, the additional steady-state total flow rates are instantaneous. Hence, the Intercept Method application adds relatively small incremental test time over that from a conventional steady-state test. Total flow rates are increased in steps to avoid hysteresis effects for the same fractional flow. The total flow rate can be reduced concurrently with stepping to the next fractional flow. Since the saturation change is significant between two consecutive fractional flows, reducing total flow rate between consequent fractional flows imposes minimal hysteresis. The Intercept method application requires CEE region to be shorter than the core length. Below a critical total flow rate, which is typically a low value, CEE region can encompass the entire core length. Below this critical rate, the pressure and saturation correction plots (Figure 3) are not linear [1]. While applying the method, it is recommended to discard the low total flow rate data that is off the linear trend [1].

Laboratory Application on Gas-Condensate System

Results of Henderson et al. [9] are evaluated by the methods of this paper. The rate, pressure drop, and saturation data are interpreted from figures in their paper. Fluid viscosities are assumed the same as those from Jamiolahmady et al. [10] The data sets are from steady-state gas-condensate relative permeability measurements with fluids of 0.14 mN/m and 0.9 mN/m interfacial tension (IFT).

Figure 6 shows pressure drop versus total flow rate for the two systems for three condensate-to-gas flow ratios (CGR). Trend lines through the data sets for each CGR are linear, but in each case, ΔP intercepts are non-zero. These non-zero intercepts (Figure 6) and shifts in saturation with increasing rate at constant CGR (Figure 7) are indicative of capillary end-effects. When intercept corrections are applied to the data sets, the net result is a set of relative permeability curves that are rate-insensitive rather than a family of curves that appear to be rate-sensitive. This is shown in Figure 7, which compares curves from the original work (white and grey data points) with those after correction for capillary end-effects (“final” data points). The corrected curve is close to that from the highest total flow rate test, which corroborates with the theory [4]. For a given IFT, the gas-condensate curve is unique (rate independent); however, change in IFT influences the curve. As expected, the relative permeability is higher at lower IFT (Figure 7).

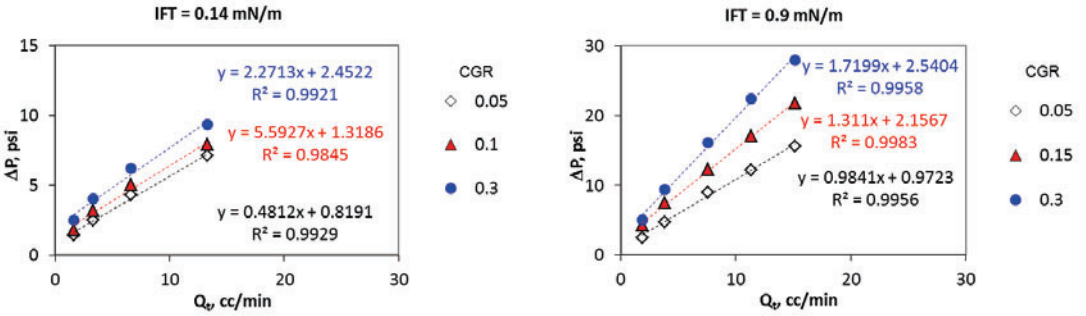


Figure 6: Pressure drop versus total flow rate for 0.14 and 0.9 dynes/cm interfacial tension systems.

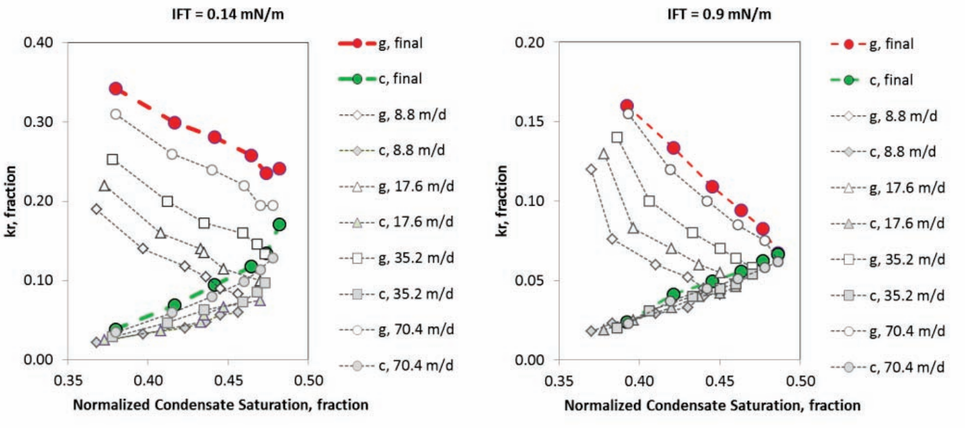
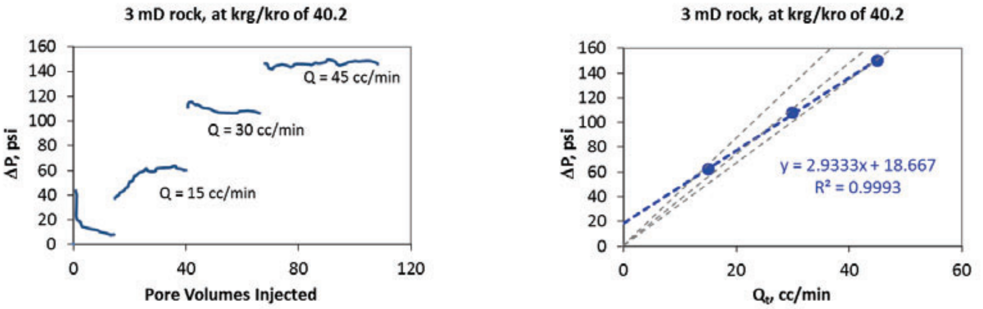


Figure 7: Gas and condensate relative permeability versus normalized condensate saturation.

Another condensate example that shows rate-independent relative permeability curves after the Intercept Method correction is provided by Gupta and Maloney [1]. Figure 6 of Ayyalasomayajula et al. [11], which is approximated as Figure 8a below, presents what is described as “typical rate versus pressure drop data” measured during gas condensate relative permeability measurements for samples from a deep marine sandstone reservoir. The data were used to show that condensate relative permeability curves are sensitive to rate and capillary number. In Figure 8b, stabilized pressure drops from Figure 8a are plotted against rate. The three data points are collinear (blue dashed line) with a ΔP intercept of almost 19 psi. Correcting for this non-zero intercept removes the rate-sensitivity that otherwise would be interpreted when the data points are considered independently (grey dashed lines on Figure 8b).



a) Pressure drop versus PV injected b) Pressure drop versus rate

Figure 8: (a) Pressure drop versus pore volumes injected[11], and (b) interpretation of results.

Laboratory Application on Gas-Water System

This example illustrates a laboratory application of the Intercept Method on a gas-brine drainage steady-state relative permeability test. The composite permeability was 8.7 mD. At the beginning of the test, the composite was completely saturated with synthetic formation brine. During the test, gas and synthetic formation brine were co-injected through the composite with increasing gas-to-brine flow ratios ranging from 0:1 to 1:0. At each steady-state condition, 3 to 4 sets of total flow rates were tested while maintaining the same gas-to-brine flow ratio. The Intercept Method was applied to correct capillary end-effect related errors in pressure drop and saturation data, which were later used to calculate corrected relative permeability curves.

Figure 9 shows steady-state relative permeability results with and without capillary end-effect corrections. Application of the Intercept Method resulted in up to 51 % pressure drop correction and brine saturation correction of up to 0.06 saturation fraction units. Because of the significant end-effect correction in this example, there is a substantial difference between uncorrected and corrected relative permeability curves (Figure 9). In this experiment, the coefficient of determination (R^2) was greater than 0.99 for all pressure and saturation correction plots except the last set (lowest S_w). Figure 10 shows the pressure and saturation correction plots for gas-to-brine flow ratio of 99:1. The experimental data follow linear trends for both the plots with about 50 % correction in pressure drop. The last point (lowest S_w) is off-trend potentially due to wrong phase pressure measurement or other experimental errors. Overall, this case study clearly demonstrates that capillary end-effects can be significant for a gas-water system, and that the Intercept Method can be applied to obtain capillary end-effect corrected relative permeability curves.

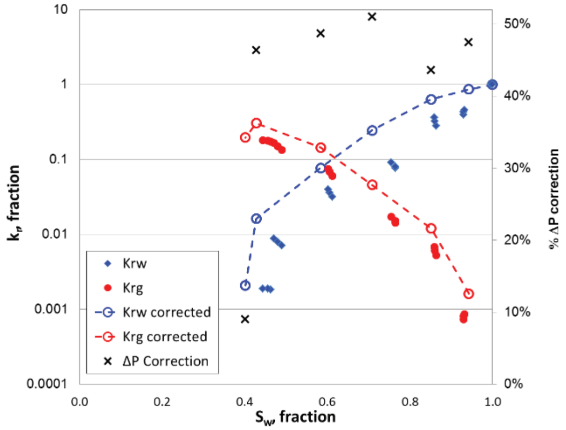
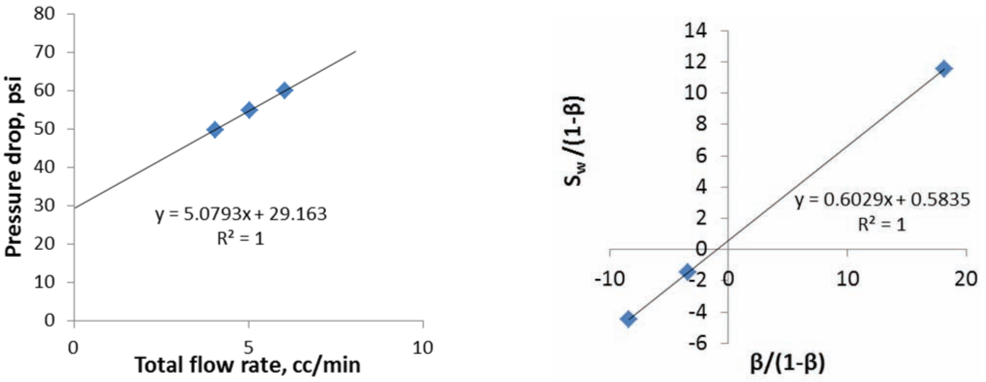


Figure 9: Gas-water drainage steady-state relative permeability test. Test data and Intercept Method corrected results are shown along with % pressure drop correction.



(a) (b)

Figure 10: Pressure drop (a) and saturation correction (b) plots using the Intercept Method at gas:brine flow ratio of 99:1.

Another example of ΔP intercept correction is shown by Grattoni et al. [12]. From transient pressure decay tests in rock partially saturated with water, they found that gas stopped flowing before pressure drop decayed to zero. They termed this non-zero ΔP the "water-blocking pressure." From multi-rate steady-state gas injection tests with constant water saturation, they also found that plots of pressure drop versus rate were linear but ΔP intercepts were positive. They suggested a saturation-dependent correction to the Darcy equation to correct for non-zero ΔP intercepts. Although there are several possible reasons for their non-zero intercepts, the data closely resembles that described in this paper.

Laboratory Application on Oil-Water System

This example illustrates a laboratory application of the Intercept Method on a data set from an oil-brine primary drainage steady-state relative permeability test. The data are from Virnovsky et al. [13] from a study in which steady-state drainage relative permeabilities were measured during repeat tests with three distinct total flow rates (low, medium and high rates of 0.2, 0.5, and 5.0 mL/min). This data set was selected because it is descriptive and readily available from the literature. Relative permeability test results from low, medium, and high rate tests are shown in Figure 11 (grey data points). Without CEE correction, there appears to be flow rate dependence in the relative permeability curves of this test. The Intercept Method was applied. Corrected results are shown in Figure 11 (green and blue data points). The Intercept Method successfully collapsed the family of lab-generated curves into a unique, rate-independent set of relative permeability curves.

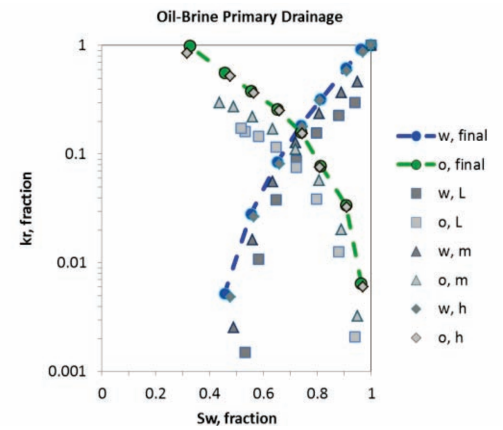


Figure 11: Lab generated, and the Intercept Method corrected primary drainage relative permeability curves.

Figure 12 shows the pressure correction plots for different water fractional flows for this test. The trends are linear with non-zero ΔP intercept. Similarly, saturation correction plots also were of good linearity (not shown). Pressure drops from measurements with the highest total flow rate (5 mL/min) were significantly higher than the non-zero ΔP intercepts in this test. For this reason, relative permeabilities from the highest total flow rate test (5 mL/min) are similar to the CCE-corrected curves.

The Intercept Method of this paper was developed after collectively reviewing data from a variety of multiphase steady-state laboratory flow tests in which several sets of rates and pressure drops were measured for each steady-state fractional flow. In each case, non-zero ΔP intercepts and saturation shifts were revealed, which led to the development of methods described in this paper.

We speculate that the need for an end-effect correction to steady-state relative permeability data has received little attention previously because most multiphase steady-state tests are not conducted with multiple rates at each fractional flow. In general, most studies that use multiple rates for each fractional flow look for rate effects, such as a velocity enhancement effect in gas-condensate systems or visco-inertial flow effects in high rate gas-liquid systems. Our impression is that when multi-rate data is available, the end-effect artifacts described herein will be evident.

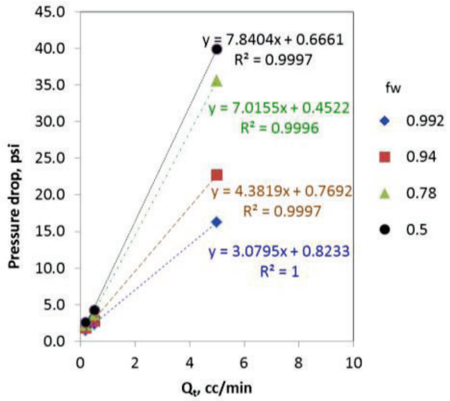


Figure 12: Pressure drop versus total flow rate at different water fractional flows for oil-water system.

Examples of this paper were drawn from the literature and in-house tests to demonstrate that end-effects influence multiphase flow laboratory data irrespective of fluids used and techniques applied in gaining the measurements. The methods of this paper are simple to apply in gaining steady-state data corrected for capillary end-effects.

CONCLUSIONS

This work demonstrates the Intercept Method that can correct capillary end-effect errors in steady-state relative permeability test data.

- The method enables attainment of CEE corrected steady-state relative permeability in systems where performing high pressure drop or high total flow rate tests would be challenging, such as in gas-liquid systems or when testing tight or clay-rich rocks.
- The Intercept Method can be applied during a test to correct for CEE errors as data is measured without necessitating the use of additional simulation, internal pressure taps, or in-situ saturation monitoring effort.
- The Intercept Method can be applied to liquid-liquid, gas-liquid and gas-condensate steady-state relative permeability data to correct for CEE artifacts. The CEE corrected plots are unique and independent of flow rates.
- The velocity enhancement effect that has been described in the literature from laboratory gas-condensate relative permeability measurements is likely the result of CEE artifacts. A gas-condensate curve is unique and flowrate independent; however, it is sensitive to IFT changes.

ACKNOWLEDGEMENTS

We thank Lisa Lun, Jim Kralik, Ted Braun (consultant), Bo Gao, David Laverick, Robert Longoria, Daniel Berry, Larry Poore, Brad Milligan, Loan Vo, Sergio Leonardi and Prateek Patel of ExxonMobil URC for their valuable contributions to this work. Appreciation is also expressed to ExxonMobil Upstream Research Company for the opportunity to present this work.

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