Improved Method of Relative Permeability Measurements Using Steady State Technique

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This paper presents an enhanced method for measuring two-phase relative permeability curves using the steady state technique. Traditional methods rely on post-experiment calibration of saturation profiles, which means the experiment is conducted without real-time saturation data. Our approach calibrates one-dimensional X-ray or Gamma-ray scans at the beginning of the experiment using methanol as a calibration fluid, providing direct in-situ saturation profiles throughout the test. This allows for better control and design of fractional flows and pump flood rates. Experiments were conducted using live-oil-brine fluids on carbonate rock samples from a giant oil reservoir in the Middle East. The new technique offers faster, more accurate data acquisition over a wide range of saturations and provides real-time quality assessment of the data.

1. Introduction

The measurement of two-phase relative permeability curves is a critical aspect of reservoir engineering, as it provides valuable insights into fluid flow behavior in porous media. Traditional methods for measuring these curves often rely on post-experiment calibration of saturation profiles, which can lead to inaccuracies and inefficiencies. Several studies have explored various techniques to improve the accuracy and efficiency of relative permeability measurements.

One of the earliest methods for measuring relative permeability was the unsteady-state technique, which involves displacing one fluid with another in a core sample and measuring the production rates and pressure drops. However, this method has limitations, including the need for complex data interpretation and the potential for capillary end effects.

The steady-state technique, on the other hand, involves establishing a constant flow of two immiscible fluids through a core sample and measuring the saturation profiles along the core. The steady state technique includes conducting calibration of X-Ray scan of the core samples fully saturated with at 100% formation brine and 100% Live-oil to use it for calculating the water and oil saturation distribution for the different ratios. This method provides more accurate and reproducible results compared to the unsteady-state technique. However, traditional steady-state methods rely on post-experiment calibration of saturation profiles, which means that the experiment is conducted without real-time saturation data.

Recent advancements in imaging technologies, such as X-ray and Gamma-ray scanning, have enabled more accurate and real-time measurement of saturation profiles. For example, Al-Yousef et al. (2000) demonstrated the use of X-ray computed tomography (CT) to measure in-situ saturation profiles during steady-state relative permeability experiments. This approach provided more accurate and detailed saturation data, allowing for better control and design of fractional flows and pump flood rates.

Also, Reed and Cense (2018) investigated the limitations and recommended improvements in in situ saturation monitoring (ISSM) using X-ray or gamma-ray attenuation techniques during coreflood experiments. They proposed a workflow to improve the reliability of saturation data.

In addition to imaging technologies, several studies have explored the use of different fluids and core sample types to improve the accuracy of relative permeability measurements. For instance, Honarpour et al. (1986) investigated the use of live-oil-brine fluids and carbonate rock samples to obtain more representative relative permeability curves for carbonate reservoirs. Their findings highlighted the importance of using reservoir-specific fluids and rock samples to obtain accurate and reliable data.

The limitation of conventional steady state techniques is the inability to obtain reference X-ray scans at 100% oil saturation until after the experiment is complete. The new approach presented in this paper builds on these advancements by calibrating the one-dimensional (1D) X-ray or gamma-ray scans at the beginning of the experiment using methanol as a calibration fluid. This new methods provide direct in-situ saturation profiles throughout the experiment., allowing for better control and design of fractional flows and pump flood rates in real-time. As a result, the new method deliver faster and more accurate data acquisition over a wide range of saturations.

2. Methodology and Experiments

2.1. Rock and Fluid Properties:

The improved steady-state relative permeability experiments were conducted on 20 core samples of 1.5inch diameter and lengths ranging between 4.64 to 7.41cm. These samples originated from three giant carbonate reservoirs (A, B, and D) with multibillion oil barrel in the Middle East, which is mainly composed of calcite (96.5 wt% ± 1.9 wt%). The core plugs selected for this study have a permeability range of 0.16 to 280 mD and porosity values between 13% and 30%., properties of the used samples are listed in **Table-1**.

Table 1. Summary of the selected core plug samples with basic routine rock properties.

Sample ID	Length (cm)	Diameter (cm)	Grain Density (g/cc)	Helium Porosity (%)	Brine Permeability (mD)
A-1	5.44	3.77	2.71	18.18	59.92
A-2	6.41	3.72	2.69	17.10	96.61
A-3	6.58	3.77	2.70	17.46	5.55
A-4	5.90	3.77	2.69	22.12	31.16
A-5	7.41	3.72	2.69	17.56	1.78
A-6	7.22	3.86	2.70	15.41	1.41
B-1	6.29	3.79	2.83	27.20	61.18
B-2	6.36	3.78	2.71	13.40	0.22
B-3	6.37	3.69	2.89	26.70	26.37
B-4	6.35	3.76	2.81	20.80	16.07
B-5	6.27	3.77	2.82	28.70	5.47
B-6	6.33	3.71	2.82	31.60	280.20
B-7	6.81	3.73	2.75	18.40	2.63
B-8	6.36	3.72	2.82	20.10	18.79
B-9	6.34	3.72	2.85	30.30	105.15
D-1	4.64	3.75	2.70	22.70	2.00
D-2	4.67	3.76	2.73	19.80	2.02
D-3	5.01	3.78	2.70	19.10	0.77
D-4	4.97	3.79	2.71	12.90	0.28
D-5	4.81	3.78	2.70	12.90	0.16

Four reservoir crude oil was used to the related reservoir core samples to perform the steady state water-oil (SSWO) experiments for both primary drainage (PD) and imbibition (Imb) cycles, to generate the relative permeability curves. A summary of the physical properties of the Live crude oil and formation water samples utilized in this study is presented in **Table 2**. The selected oils showed viscosities between 0.31 and 2.9 cP and densities ranging from 0.68 to 0.85 g/cc. The water viscosities ranged from 0.4 to 0.54 cP, and the water densities ranging from 1.1 and 1.14 g/cc.

Table 2. Properties of Live Crude Oil and Formation Water

Reservoir Name	Oil viscosity (cP)	Water viscosity (cP)	Oil Density (g/cc)	Water Density (g/cc)
A	0.31	0.45	0.68	1.11
B	2.90	0.54	0.85	1.14
D	0.49	0.40	0.69	1.10

The details of the adopted experimental protocols and procedure, for the improved method of relative permeability measurements using steady-state technique, are described in the following:

2.2. Crude oil and Core Samples Preparation:

Crude oil samples were filtered, degassed, and centrifuged to remove all solids and water. Then, live oil crude oil samples were prepared by recombine the dead crude oil and gas samples by matching the bubble point pressure and GOR for each reservoir.

Initial plug sample preparations and basic measurements were performed as follows:

a) Cleaning plug samples by flooding solvents (Toluene, Methanol and mix with Chloroform)
b) Samples were oven-dried by hot oven
c) Measure routine core analysis (porosity and air permeability) on the cleaned core sample.
d) Vacuum saturates the core with formation water to achieve 100% brine saturation. Loading of 100% saturated sample in the high pressure high temperature (HPHT) steady state rig to proceed with SSWO drainage and imbibition cycles.

The plug sample was encapsulated in Teflon tape, annealed Nickel foil and heat shrinkable Teflon tubing before it was mounted into a reservoir condition core holder and loaded to reservoir conditions.

2.3. Relative Permeability measurement (Drainage and Imbibition) and Wettability restoration:

Once the plug sample was mounted in the reservoir conditions rig, SSWO drainage cycle using live oil was performed using 9 water oil fractions at different ratios followed by 2 bump flood fractions. Once the Sample is at S_{wi} will proceed with ageing up to 3 to 4 Weeks. The detailed procedure is in the following:

a) The loaded 100% saturated sample in the HTHP are flooded by the formation doped brine and to measure kw at 100% formation doped brine at ambient and reservoir condition followed by 100% base scan.

b) The sample is flooded by methanol to displace the doped brine until 100% methanol is reached. Then, the methanol base scan is acquired and will be used as a temporary representative for the 100% live oil base scan for determining saturation profiles during drainage and imbibition cycle.
c) Samples are re-flooded with doped brine to replace methanol by gradually increased the injection rates to assure 100% displacement of methanol.
d) SSWO full drainage test starts with total of 9 fractions (100% water, 99%-1% water oil, 95%-5% water oil, 85%-15% water oil, 50%-50% water oil, 25%-75% water oil, 15%-85% water oil, 5%-95% water oil, 1%-99% water oil, 100% live oil at S_{wi} followed by 2 bump flood oil fractions at S_{wi}.
e) After that, wettability restoration is processed by ageing the sample up to 4 weeks, with live oil flooding performed once week to measure ko at swi.
f) Then, the SSWO imbibition cycle is started and using the same fractions mentioned above in the drainage process (step-d). Final fraction is k_w at S_{or}. Additional 2 bump flood water fractions at S_{or}.
g) Karl fischer test followed by cleaning, and then, 100% live oil base scan is acquired. Also, k_o is measured at this 100% live oil saturation.

Flood direction was chosen from bottom to top for gravity stable displacement during the imbibition flood. During acquisition of gamma reference scans (oil and water), required to perform ISSM calculations, specific oil (k_o) and water (k_w) permeability were measured at reservoir conditions.

3. Results and Discussion

In this section, we compare the calibrated the ISSM profiles using both the 100% methanol and 100% live oil base scans. As an example, Fig. 1 shows the X-ray scan profiles between 100% live-oil and 100% methanol saturation for three samples A-2, A-5, and A-6 with permeability of 96.6, 1.78, and 1.41 md, respectively. The difference between two scans was observed as 1.17%, 0.82%, and 1.77% for A-2, A-5, and A-6, respectively.

Fig. 1. X-ray scan profiles versus plug length for 100% methanol and 100% live oil for three samples A-2, A-5, and A-6 with permeability of 96.6, 1.78, and 1.41 md, respectively. The difference between two scans was observed as 1.17%, 0.82%, and 1.77% for A-2, A-5, and A-6, respectively, indicating no correlation between the permeability and difference values of scans.

Although, the difference between the acquired scans was very minimum in all the samples, and was found ranging from 0.06 to 1.77%. We observed that there is no direct correlation between permeability and difference values of scans. However, the X-ray count number was correlated with the pore volume as shown in Fig. 2. The X-ray counts increases with larger pore volume samples, indicating that with larger pore volume the X-ray counts increases.

Fig.2 – 5 shows the X-ray count versus pore volume for samples saturated with 100% oil, 100% methanol, and 100% water for the tested samples. We observed that the samples that are saturated with methanol and crude oil and have the similar gradient, while the gradient is different when the samples are saturated with brine.

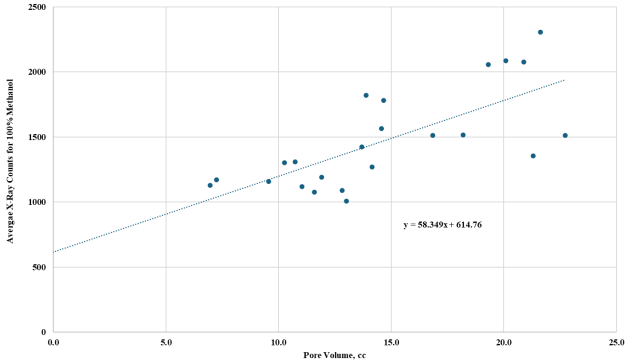

Fig. 2. Average X-ray counts plug samples saturated with 100% methanol versus pore volume of plug samples: the relationship shows the X-ray counts increases with larger pore volume samples.

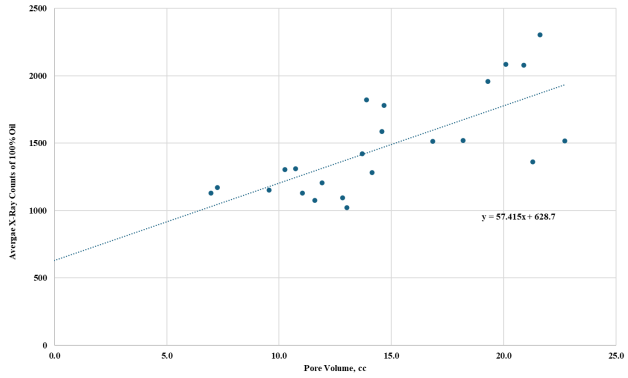

Fig. 3. Average X-ray counts plug samples saturated with 100% oil versus pore volume of plug samples : the relationship shows the X-ray counts increases with larger pore volume samples.

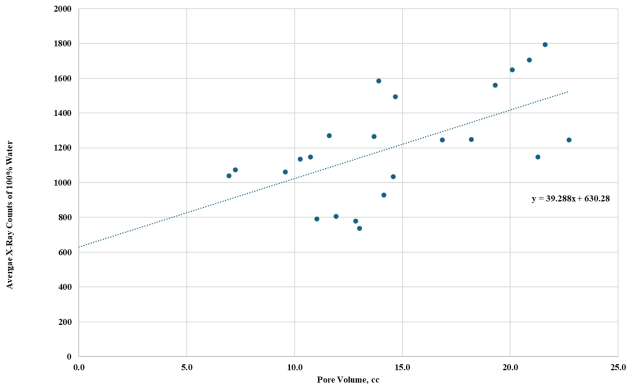

Fig. 4. Average X-ray counts plug samples saturated with 100% water versus pore volume of plug samples : the relationship shows the X-ray counts increases with larger pore volume samples.

Moreover, the comparison of calculated saturations for water-oil and water-methanol at ratio-1 (FW-1: 99% water, 1% oil) showed minimal differences ranging from 0.07% to 0.41%. However, this difference increases as more oil is displacing the water. The maximum deviation occurred toward the final fractions of primary drainage cycle (Bump rate-2) at S_{wi} where the difference ranging from 0.53% to 2.29% as shown in Table-3.

Table 3. Difference in Calculated Saturation Between Water-Oil and Water-Methanol (%)

Sample ID	D-2	D-3	D-4	D-5
100%-Water	0.00	0.00	0.00	0.00
FW-1	0.07	0.31	0.48	0.08
FW-2	0.17	0.81	0.59	0.13
FW-3	0.25	1.12	0.66	0.18
FW-4	0.57	1.38	0.73	0.24
FW-5	0.72	1.62	0.83	0.30
FW-6	0.81	1.75	0.92	0.34
FW-7	0.96	1.87	1.01	0.39
FW-8	1.13	2.01	1.11	0.44
FW-9	1.24	2.13	1.21	0.49
Bump-1	1.25	2.21	1.25	0.51
Bump-2	1.26	2.29	1.31	0.53

X-ray scans are dependent on the fluid densities Alhammadi et al. (2017). **Fig.5** presents the density of methanol at various pressures and temperatures (NIST Chemistry database). We analyze the fluid density for the used methanol and oil samples (A, B and D). We observed that the difference between the methanol density and oil samples (A, B and D) are 12%, 5% and 11%, respectively. In addition, the deviation between the 100% oil and 100% methanol scans are in samples A-5, B-8 and D-3 was 0.82%, 0.16% and 0.3%, respectively.
Finally, we believe that methanol has a minimal effect on the wettability alteration compared to the crude oil.

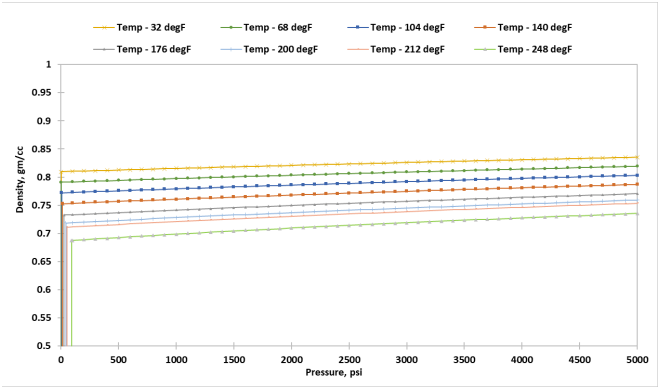

Fig. 5. Methanol Density Versus Pressure at Different Temperature

4. Conclusions

In this study, we presented an improved method for measuring two-phase relative permeability curves using the steady-state technique. By using methanol as a calibration fluid at the beginning of the experiment we were able to obtain direct in-situ saturation profiles throughout the experiment. This approach allowed for better control and design of fractional flows and pump flood rates, resulting in faster and more accurate data acquisition over a wide range of saturations.

The experiments conducted on carbonate rock samples from three giant oil reservoirs in the Middle East demonstrated the effectiveness of this method. The use of live-oil-brine fluids provided more representative relative permeability curves, and the real-time quality assessment of the data ensured the reliability of the results.

Overall, the enhanced steady-state technique offers significant improvements over traditional methods, providing valuable insights into fluid flow behavior in porous media and contributing to more efficient reservoir management.

5. Nomenclature

- SSWO: Steady-State Water-Oil
- PD: Primary Drainage
- Imb: Imbibition
- HPHT: High Pressure High Temperature
- Kw: Water Permeability
- Ko: Oil Permeability
- Swi: Initial Water Saturation
- Sor: Residual Oil Saturation
- ISSM: In-Situ Saturation Measurement

6. References

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