The Effect of Wettability and Relative Permeability Hysteresis On Fluid Displacement in Transition Zone

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Abstract: Many reservoirs have a thick transition zone that contains a considerable amount of oil in place. Modelling fluid movement in such reservoirs requires reliable SCAL data which in many cases are limited or unavailable. This work illustrates how to generate SCAL data (relative permeability and capillary pressure) from limited laboratory measurements. Studying the impact of "scanning" curves, to model relative permeability, capillary pressure hysteresis, and wettability on fluid displacement in a simulated transition zone reservoir. Based on water-flooding measurements of ten cores (4 cores are water-wet and 6 cores are oil-wet). A relationship between the initial oil saturation and residual oil saturation was established. Using calculations to generate "scanning" curves of oil relative permeability and capillary pressure at different initial oil saturation values for the water-wet and oil-wet systems. Studying the impact of the "scanning" curves and wettability, 1-D Black-Oil dynamic model was used to simulate a reservoir transition zone. The model was run until no significant oil production was produced by injecting two brine pore volumes to reach residual oil saturation. The results of comparing oil production rate, cumulative oil production, water cut, and displacement efficiency show a significant difference (16% in displacement efficiency) due to wettability. By comparing similar parameters, the results show at least an 11% difference in displacement efficiency between using oil relative permeability "scanning" curves and no "scanning" curves (single oil relative permeability curve). The residual oil saturation at the end of the run (Sor) is also different due to the effect of wettability. The oil-wet system shows lower residual oil saturation which agrees with the laboratory measurements. In conclusion, this work shows the importance of modelling fluid movement, especially in thick transition zone reservoirs with a considerable number of reserves.

1 Introduction

Modelling fluid displacement is important during production since it dictates future production forecasts and field development plans. Especially, in reservoirs with thick transition zone where both phases (oil and water) are mobile. Unfortunately, many such reservoirs have limited Special Core Analysis (SCAL) data or no SCAL data at all. In this situation, the reservoir simulation engineer may use the open-hole logs to generate the saturation-height function (log-derive drainage capillary pressure) to initialize the **model [1],** but during history matching and predictions imbibition saturation functions (capillary pressure and relative permeability) are required to simulate fluid movement. In this case, analogue data may be used with high uncertainty or require SCAL data which will take time and money. The objectives of this work is to illustrate how to generate capillary pressure and relative permeability from limited laboratory data:

- Establish a relationship between initial oil saturation (Soi) and residual oil saturation (Sor) for water-wet cores (Amott water wettability index Iw > 0.9) and oil-wet cores (Amott water wettability index Iw near zero).

In order to meet the first objective, a recent publication in 2016 by Nayef Alyafei and Martin J. Blunt "The effect of wettability on capillary trapping in carbonates" [2] was used as an example to generate the relationship between the residual oil saturation (Sor) and the initial oil saturation (Soi) for one reservoir rock type Portland limestone. The core flooding measurements done for types of wettability from spontaneous water imbibition: The Amott water index, Iw > 0.9 for four cores and six cores with the altered-wettability systems, there is no spontaneous water imbibition, Iw near zero. Table 1 shows the core data which was used to derive the Sor versus Soi relationship.

- Study the impact of wettability on fluid displacement in the transition zone.
- Study the impact of using "scanning" curves for relative permeability data and capillary pressure on fluid displacement in the transition zone

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Table 1. Core Data used for Core-Flooding Tests [2].

Core Label	D(mm)	L(mm)	Porosity (%)	K (m^2)	Soi	Sor	Iw
P1	37.85	76.38	22.8	5.24×10^{-15}	0.27	0.19	0.9
P2	37.84	76.19	19.7	3.2×10^{-15}	0.4	0.3	0.92
P3	37.95	76.35	19.8	1.9×10^{-15}	0.56	0.39	0.93
P4	37.95	76.25	18.0	1.8×10^{-15}	0.68	0.44	0.95
P5	37.89	76.28	18.9	7.2×10^{-15}	0.49	0.27	0
P7	37.9	76.25	17.0	1.3×10^{-14}	0.38	0.18	0
P8	37.92	76.35	21.0	6.2×10^{-15}	0.38	0.21	0
P10	37.84	76.09	20.9	9.9×10^{-15}	0.29	0.12	0.11
P11	37.73	76.38	19.4	3.57×10^{-15}	0.83	0.38	0.09
P12	37.89	76.21	19.2	5.77×10^{-15}	0.61	0.25	0.17

For more details of wettability and core-flooding measurements see the reference above.

1.1 Laboratory Procedure

The following is a summary of the laboratory procedure for more information, please refer to reference [2].

1-Prepare the core: Fully saturated with brine (inject about five pore volumes PV of brine).

2-Primary Drainage: Inject n-decane (non-wetting phase) at constant pressure. keep track of differential pressure until the end of drainage (no change of brine effluent). At this step initial oi saturation (Soi) was calculated.

3-Spontaneous water imbibition: Take the core to Amott cell, monitor the spontaneous water imbibition until no further n-decane is produced at the top of the cell.

4-Waterflooding (forced water injection): Apply a confining pressure and inject 5–10 PV of degassed brine until the residual oil saturation (Sor) is reached.

5- . Altered-wettability scenario: To alter the wettability of the rock at ambient conditions, add 1.5 wt% of cyclohexanepentanoic acid. (Fluid A) The procedure for the altered-wettability core flooding experiments is exactly the same as the water-wet experiments; however, the only differences are that instead of injecting pure n-decane, we inject fluid A. Place the altered core in the Amott cell for a duration of 30 days or more and waterflood the core with 10 PV of brine. The table below shows the properties of n-Decane and fluid A (reference [2]).

Fluid	ρ [kg/m^3]	μ [mPa s]	σ [mN/m]	θ_l [deg.]
n-Decane	728.8 ± 0.02	0.92	52.3 ± 0.4[a]	37.9 ± 2
A	731.5 ± 0.02	0.91	27.52 ± 0.08[a]	130 ± 3

This study concerns only of the laboratory measurements of initial oil saturation (Soi) and residual oil saturation (Sor) for different core wettability. Therefore, define the relationship between Sor and Soi for water-wet cores and oil-wet cores. The rest of this study uses this relationship to generate saturation functions (capillary pressure and relative permeability) using equations. This work can be used if SCAL data is limited or not available at all. More important is to show the impact of using different SCAL data (one set of water wet and other set of oil-wet) on fluid displacement in transition oil zone using reservoir simulation model.

1.2 Background

Hysteresis represents the "path" or history dependence of the physical system. Saturation which is the increasing wetting phase (Imbibition) and desaturation which represents decreasing of wetting phase (drainage) could happen in different locations at the same time in the reservoir. Since both relative permeability and capillary pressure are functions of wetting phase saturation, they should reflect saturation changes in the reservoir by following the proper "path" or curve of relative permeability of capillary pressure depending on the direction of saturation change. The scanning curves are presenting hysteresis of relative permeability and capillary pressure.

2 Methodology

Plotting residual oil saturation versus initial oil saturation for both wettability systems show an acceptable relationship between Sor and Soi as shown in Figure 1 below: The above curve is for water-wet cores (Iw > 0.9) and the lower curve for oil-wet (altered) wettability cores (Iw near zero).

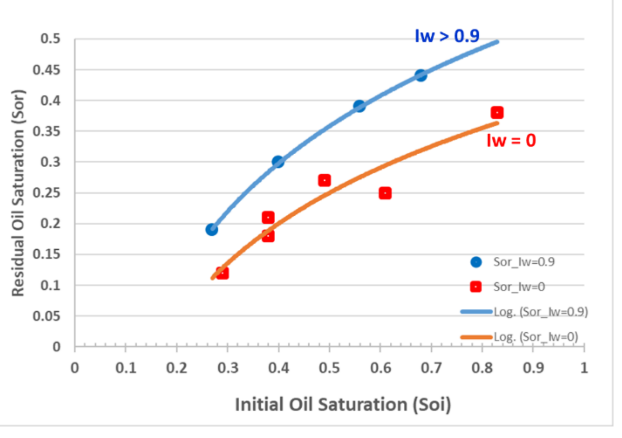

Fig. 1. Relationship between Sor and Soi for both wettability systems.

Curve fitting technique was used to define the relationship with $R^2 > 0.9$. Land correlation [3] as shown by equation 1 may be used to fit the laboratory measurement data or other fitting techniques may be used.

$$Sor = \frac{Soi}{(1 + C * Soi)} \qquad (1)$$

Where C is a fitting parameter. After defining the relationship between Sor and Soi, Sor can be calculated at any value of Soi. The value of Sor is important to determine the end points for both the relative permeability curves and capillary pressure as well. This will be shown later on this work.

2.1 Generation of Relative Permeability and Capillary Pressure "scanning" Curves

There are limited references available to calculate relative permeability and capillary pressure from correlations. In this work Corey [4] equation used to generate "scanning" curves for relative permeability of oil (Kro) for water-oil system. Bentsen **[5]** correlation used to generate "scanning" curves for Imbibition capillary pressure (Pcow). The curves were generated at equal increments of water saturation (ΔSw = 10%). The hysteresis of relative permeability and capillary pressure are presented by scanning curves of the imbibition process (wetting phase displacing the non-wetting phase).

2.2 Relative Permeability Scanning Curves:

The starting point of the Kro scan curve (Kro*). It represents the maximum value for each Kro scan curve. Also we need the end point of the curve, the value of Sor at which Kro=0 (Kro at Sor). The residual oil saturation was calculated by relationship between Sor versus Soi in equation (1) which is the best fit curve of Sor versus Soi.

If no drainage relative permeability data is available, the maximum value of Kro may be assumed as one (Kro* = 1).

The next scanning curve started at Sw = Swi + 10% and so forth. After determining Kro* and Sor, Corey equation **[4]** can be used to calculate Kro at different values of oil saturation (So) to generate a full scan curve as follows:

$$Kro = Kro^* \left[\frac{So - Sor}{Soi - Sor} \right]^{no} = Kro^* (Son)^{no} \qquad (2)$$

Where:

Kro* = Maximum Kro (Kro at Swi)

So = Oil saturation at any Sw value

Sor = Residual oil saturation

Soi = Initial water saturation = 1-Swi

no = Corey coefficient for oil

Son = Normalized oil saturation

Figure (2) and Figure (3) show relative permeability curves use a logarithmic scale to zoom in on the lower values of Kro. As noted, the scanning curves of Kro with Iw close to zero are shifted to the right which indicates lower values for Sor compared with curves having Iw > 0.9. This observation is consistent with the relationship of Sor versus Soi shown in Figure 1..

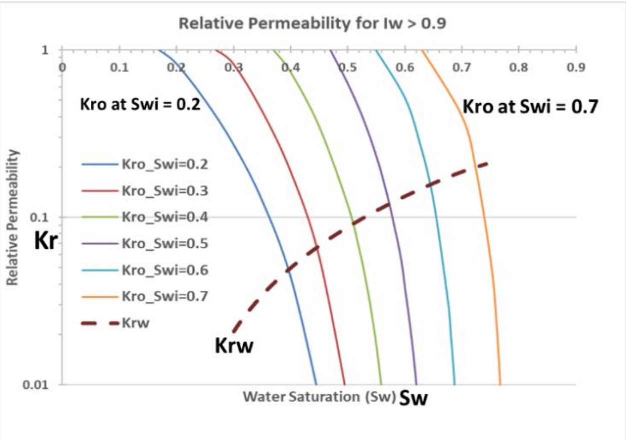

Fig. 2. Oil relative permeability scanning curves for Iw > 0.9

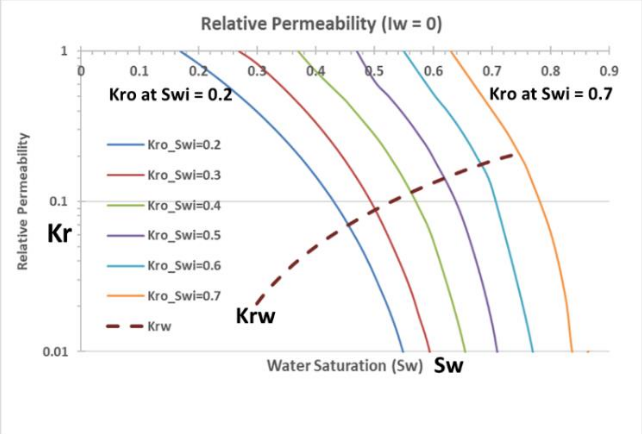

Fig. 3. Oil relative permeability scanning curves for Iw = 0

2.3 Capillary Pressure Scanning Curve

The capillary pressure scanning curves must be consistent with the relative permeability curves in terms of starting point (Swi) and end point Sw at Sor.

The capillary pressure scanning curves were generated in two parts; the first part is to calculate the spontaneous Imbibition capillary pressure and the second part is to calculate the forced Imbibition part using Bentsen **[5]** equation. The first spontaneous Imbibition curve was generated using the first point from the drainage capillary pressure (Pcd) at Sw = Swi. The second curve at Sw = Swi + 10% and so forth. The end point of the spontaneous Imbibition curve is at Pc = 0 was calculated by assuming correlation of Sw* (Sw at Pc = 0) versus Swi as following:

$$Sw^* = a + bSwi \qquad (3)$$

Where a and b contents in this study (a=0.53 and b=0.36). The scanning spontaneous Imbibition curve can be generated by using the two points (Swi,Pcd) and (Sw*,0) by the following equation **[6]**:

$$Pcsi = Ci \left[\frac{1}{(Sw - Swi)} - \frac{1}{(Sw^* - Swi)} \right] \qquad (4)$$

Where:

Pcsi = Spontaneous imbibition Pc

Ci = Constant coefficient.

Swi = initial water saturation

Sw* = Water saturation at Pc = 0.

Ci can be estimated by trial and error until it converges when Pcsi = Pcd at Sw = Swi and Pcsi = 0 at Sw = Sw*.

The second part is to calculate the forced Imbibition by using Bentsen equation **[5]**. The first point in this curve is at Sw = Sw* and Pc=0 and the end point is at Sw = 1- Sor. For consistency, Sor values are similar to those in the relative permeability curves. The following equation was used to calculate forced Imbibition Pc (Pcfi):

$$Pc_{fi} = \frac{2 - Nu}{(1 - Nu) * Be * \left(1 - Swn^{(1-Nu)}\right)} \qquad (5)$$

$$Swn = \frac{1 - Sor - Sw}{1 - Sor - Sw^*} \qquad (6)$$

Where:
Pcfi = Forced Imbibition capillary pressure
Nu = Constant coefficient
Be = Bentsen constant
Swn = Normalized water saturation
Sw* = water saturation at Pc = 0

Figure 4 shows the scanning curves for capillary pressure used with the relative permeability scanning curves as saturation functions for simulation runs.

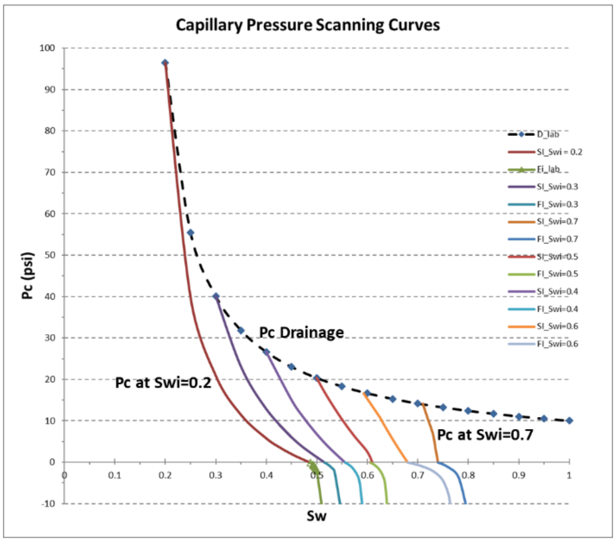

Figure 4: Scanning curves for capillary pressure.

At this point a complete set of saturation functions can be used as input SCAL data into the simulation mode.

3 Simulation Model

A simple 1-D simulation model was constructed to study the impact of wettability and scanning curves on fluid displacement in transition zone reservoir.

The only variable in simulation model is the SCAL data every other data is the same in all simulation runs. The initial water saturation at the top of transition zone is about 40% and the bottom of the zone is 100% based on open hole logs. There is a gradual change in water saturation from top to bottom. There is about 100 feet deference in depth between the top zone and bottom zone. The model size in only twenty grid cell and it has one producer at the top of zone and one injector at the bottom of zone. Figure 5 shows the water distribution in the simulation model. The average porosity is 18% and average permeability is 100 m Darcy. The difference in depth between the injector and producer (crest to flank) is about 100 feet. The original oil in place (STOOIP) is 1.755 million.

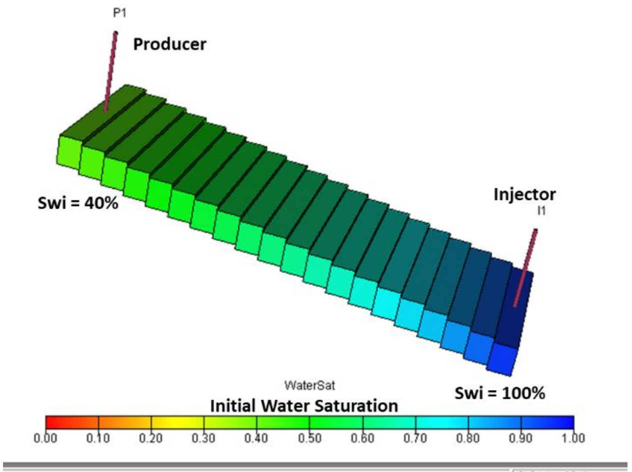

Figure 5: Initial water distribution in the simulation model.

3.1 Simulation Cases

To study the impact of wettability and scanning curves for oil phase relative permeability, four cases were considered in this work as shown in Table 2. The impact of wettability can be observed by comparing the results from case 1 and case 2.

Also by comparing the results from case 3 and case4.

To study the impact of using scanning curves, the results from case 1 and case 3 with similar wettability index. Also comparing the results from case 2 and case 4 with similar wettability index.

Table 2: Description of simulation cases

Case Name	Description of Case	Number of Kro curves	Wettability index
Case 1	No scanning curves	one starting at Swi = 0.4	Iw > 0.9
Case 2	No scanning curves	one starting at Swi = 0.4	Iw near 0
Case 3	Using scanning curves	Six curves from Swi=0.2 to Swi=0.7	Iw > 0.9
Case 4	Using scanning curves	Six curves from Swi=0.2 to Swi=0.7	Iw near 0

3.2 Results of Simulation Cases

To study the effect of wettability on fluid displacement, the results from case 1 with results from case 2. Figure 6 shows oil production rate (STB/D) and cumulative oil production (STB) versus the amount of water injected in terms of brine pore volume injected (BPVI).

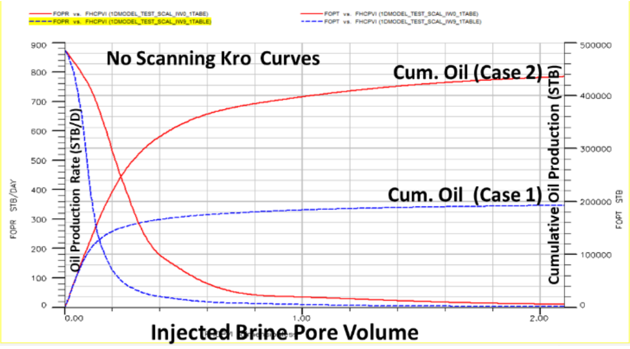

Figure 6: Oil rate and cumulative oil production (cases 1 & 2)

After injecting 2.2 BPVI of water case 2 (Iw =0) has more oil production than case 1 (Iw > 0.9) of about 14% of STOOIP.

Similarly, comparing case 3 (Iw > 0.9) and case 4 (Iw =0), but using Kro scanning curves. Figure 7 show oil production rate and cumulative oil production versus BPVI. After injecting the same amount of water, case 4 has more oil production than case 3 of about 16% of STOOIP.

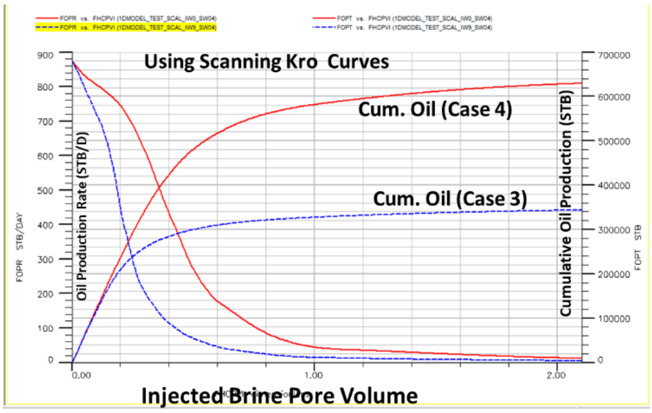

Figure 7: Oil rate and cumulative oil production (cases 3 & 4)

To study the impact of using Kro scanning curves, the cases with similar wettability were used for comparisons. Figure 8 shows comparisons of case 1 (without Kro scanning) and case 3 (with Kro scanning) both cases having same similar wettability index Iw > 0.9 (water wet).

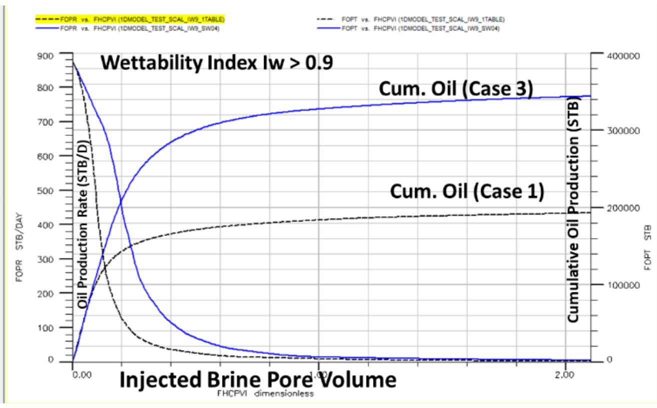

Figure 8: Oil rate and cumulative oil production (cases 1 &3)

After injecting same volume of water (2.2 BPVI), case 3 with Kro scanning has more oil production than case 1 which about 9% of STOOIP. As observed from the simulation model Kro scanning curves makes oil more mobile. Similar results were obtained after comparing case 2 and case 4 with similar wettability index Iw near zero (oil wet).

Figure 9 shows the oil production rate and cumulative oil production from case 2 (without Kro scanning) and case 4 (with Kro scanning). After injecting same volume of water (2.2 BPVI), case 4 with Kro scanning has more oil production than case 1 which about 11% of STOOIP. As noted before the oil wet cases (2 and 4) have more oil production than water wet cases (case 1 and 3).

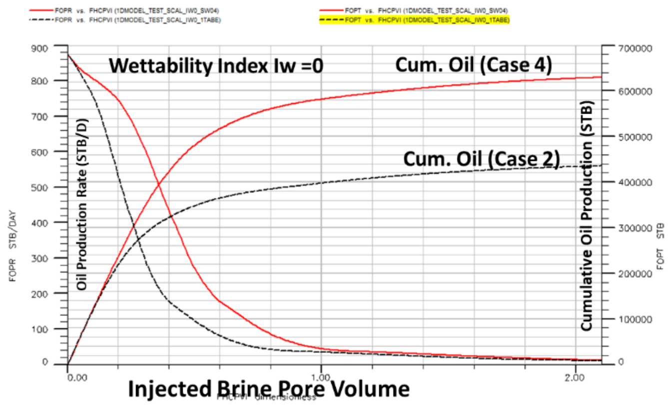

Figure 9: Oil rate and cumulative oil production (cases 2 & 4)

3.3 Discussion of Results

To evaluate the both impacts (wettability and using Kro scanning curves) the four cases were compared together. Figure 10 shows the cumulative oil production and Figure 11 shows the water cut from all cases.

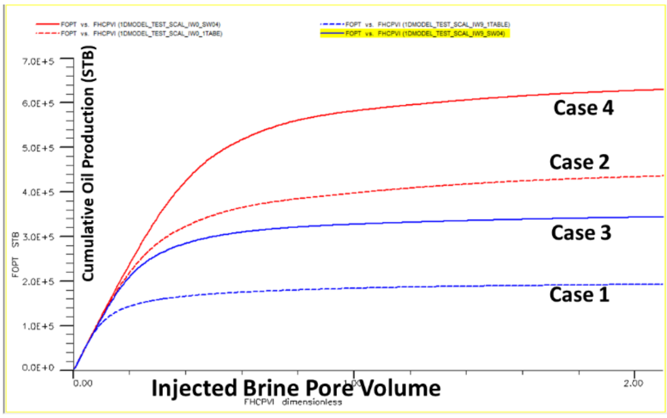

Figure 10: Cumulative oil production form all cases.

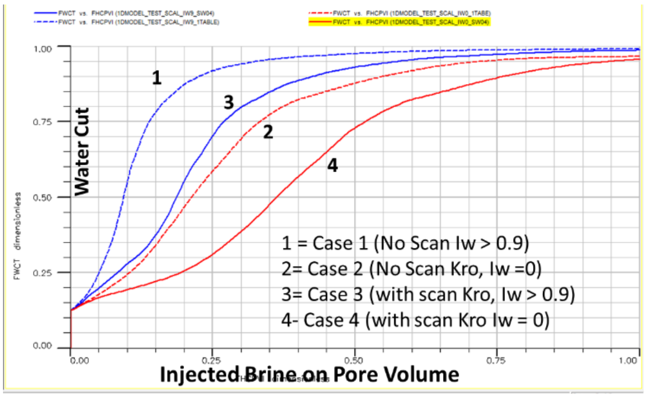

Figure 11: water Cut form all cases.

From Figure 10 and Figure 11, the wettability has more impact than using Kro scanning curves. Cases 2 and 4 with wettability index Iw near zero having more oil production and lower water cut. However, using of Kro scanning curves also has an impact of about 10% of OOIL difference. The shape of oil relative permeability as well as the value of residual oil saturation (Sor) at the end point of Kro are both important in modelling fluid displacement in general and more critical in reservoirs with thick transition zones. Figure 12 shows the values of residual oil saturation (Sor) at the grid block of producer well versus BPVI.

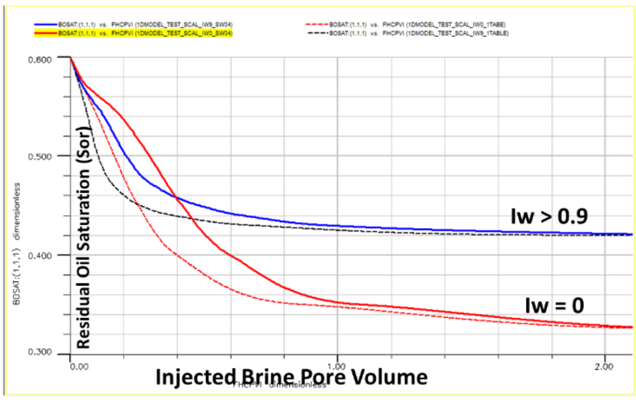

Figure 12: Residual oil saturation at the producer well.

Initially, the oil saturation (Soi) at the producer is 60% after injecting 2.2 PV of water, the oil saturation reduces to 32% (Sor) in case of wettability index (Iw) near zero. However, the cases with Iw > 0.9 it reduces to 42%. These results are in agreement with laboratory measurements shown in Figure 1.

4. Conclusions

From the above results, the following points summarizes the conclusions:

- Wettability has an important role in fluid displacement and should be not overlooked during measurements of relative permeability.
- Oil relative permeability scanning curves also has an important role in oil movement.
- This paper shows that saturation functions (relative permeability and capillary pressure) should not be ignored in reservoir simulation.

5. Acknowledgment

The author would like to acknowledge the Arabian Gulf Oil company (AGOCO) for their cooperation with the University of Benghazi to allowing publishing this work.

6. References

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