

## Adjusting Relative Permeability Measurements to History Match Water Production in Dynamic Simulation Models

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### Abstract

Most of field development plans need a countable simulation model. Simulation models are considered dependable when they match all aspects of the field's history-performance. This is achieved by matching pressure data and production phases of oil, water and gas production and injection. Many factors affect the process of history match. The most important factor is the relative permeability, which affects the partial flow of fluid phases through rock conduits. Measuring relative permeability and adjusting it to be included in simulation model is our focus in this work.

Field 'X' is in our interest in this study. The field is under of water flooding implementation. After water-flooding project has been started, field 'X' suffered from high water cut (W.C) rates in large oil producers and low oil production rates. This urged to restudy the field and consequently we needed to build a full simulation model with a proper history-match. Special Core Analysis test with unsteady-state displacement experiment for relative permeability measurement has been performed for well 'X-4'.

In this paper, we will show you how to process relative permeability data and adjust them to be introduced into simulation model to achieve a good history match performance.

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### Introduction

Dynamic simulation models are under the focus of many recent researches. These researches considered various aspects of reservoir modelling as geological prediction through relative permeability curves (Tarantini et al., 2021) [1], modelling gas reservoirs and identification of two-phase flow by the effect of hydrate dissociation (Deng et al., 2022) [2] and the enhancement of oil recovery through low injection rate in low permeability reservoirs (Aslanidis et al., 2022) [3]. The goal of reservoir engineers is to build a countable model that mimics the actual behaviour of reservoirs. The process of building a simulation model go through many steps of initializing and history matching to achieve a dependable forecast while preserving actual geological parameters, rock properties and fluid properties [4]. After initializing the dynamic model, the step of history matching requires matching pressure and production parameters, which is a difficult, lengthy and time-consuming process.

History match is an iterative process where the input data are adjusted to achieve an output that matches the actual performance [5]. Oil, Water and

Gas rates should be matched with the actual performance of reservoir to validate the simulation model. This process should be applied over the whole field, regions, groups then the production and injection wells and finally over the reservoir zones.

Matching production rates depend on several parameters, which are pressure, relative permeability curves, productivity index of the formation and wells' schedule. Multiphase flow is always a matter of concern in this process, where the [6].

Relative permeability is the governing parameter of phase flow affinity. It is the most important parameter especially in the phase of simulation forecast and directly affects the resulted recovery. It is represented as a dimensionless function with saturation. It is an important element in defining residual oil saturation ( $S_{or}$ ), irreducible water saturation ( $S_{wr}$ ), trapped gas saturation ( $S_{gr}$ ), and critical gas saturation ( $S_{cg}$ ). Relative permeability curves are greatly affected by the wettability and hysteresis.

The curves of relative permeability can be generated by mathematical methods and correlations introduced by many researchers, however the best way of identifying relative permeability is through

different experimental processes in laboratories. Sample cores are collected from wells representing different reservoirs and core plugs are selected in different facies of reservoir to cover as many different rock types as possible. Those cores are sent to laboratory to apply special core analysis (SCAL) to measure capillary pressure, relative permeability and resistivity index.

The main idea behind laboratory experiments in measuring relative permeability data for the reservoir under a study is mimicking the actual multiphase flow of fluids in core plugs. This is done by measuring the production parameters of the different phases of the core. Obtaining valid relative permeability data depend on many factors and test procedures. The problems of the test may arise from the following [7]:

- Changes in wettability due to problems in plugs preparation
- Variation in important affecting factors as initial saturation, pore geometry, overburden stress, temperature interfacial tension and viscosity as stated by [8]
- The experiment circumstances do not respect all model assumptions

Relative permeability data is always prone to inefficiency measurements or unsuitable experimental procedures. Hence, this leads to a necessity of quality checks or even amendments according to the uncertainty with that data. This work shows the manipulating actual relative permeability data can achieve a reliable history match while respecting the geological and physical parameters of reservoir.

Relative permeability curves are introduced to most of dynamic simulation models as end-points and values of relative permeability at different saturations. The relative permeability is the ratio between effective and absolute permeability, which defined mathematically as:

$$k_r = \frac{k_p}{K} \text{ (Equation 1) [9]}$$

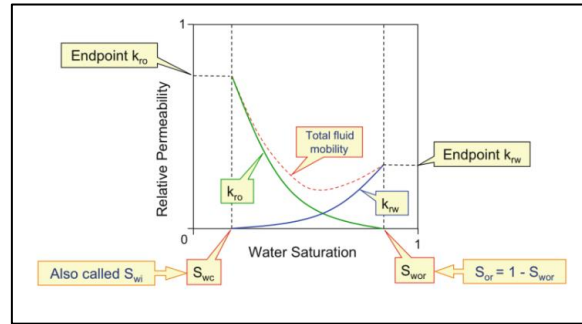
Where,

$k_r$  = Relative permeability of a certain phase (Oil, Gas or water)

$k_p$  = Effective Permeability of the phase

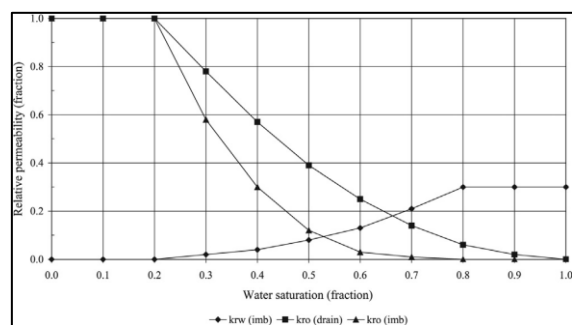
$K$  = Absolute permeability of the rock

Before we move further through this work, we need to be familiar with the end-points that figures the relative permeability curves. As shown in Figure 1 the end-points are represented in;  $S_{wc}$  (Critical water saturation by which the water starts to flow),  $S_{or}$  (is the residual oil saturation below which oil stops to flow),  $k_{ro}$  (Relative permeability of oil) and  $k_{rw}$  (Relative permeability of water).



**Figure 1:** Typical Oil-Water Relative Permeability Curve (Ringrose, Philip; Bentley, Mark, 2021) [9]

Changes in wettability also is a major factor to be identified, because it really affect the shape of the curve as shown for the cases of drainage and imbibition in Figure 2 [10].



**Figure 2:** Water-Oil Relative Permeability Curves [10]

## Materials and Methods

### Relative Permeability experimental measurements

Three main types of experimental works that derive relative permeability data, which are the steady state [11], unsteady-state (Bennion and Thomas, 1991) [12] and centrifuge method [13]. Every method has its own advantages and disadvantages.

#### Steady-State displacement

In this method, wetting and non-wetting phases are injected at different rates. Saturations are measured through steps of dropping pressure stages. The flow rates are changed through the experiments and a stabilized saturation for each phase is recorded. We take the stabilized saturation at a constant pressure drop in each stage. From Darcy's law the relative permeability is calculated by the knowledge of saturation and flow rate of each phase. This equilibrium state is what distinguishes this method. The main advantages of this method is its simplicity, and elimination of viscosity effect problems. On the other hand, its disadvantages are; it is a lengthy process and expensive and it is not countable in representing the saturations to mimic fluid displacement (Heaviside et al., 1983) [14]. This method cannot represent a displacement of a fluid by another fluid.

## Unsteady-State displacement

In this method the core plug is saturated with the fluid then displaced by a displacing fluid while monitoring the pressure differential then calculate the relative permeability. This approach is based on Buckley and Leverett theory. This method has advantages of being a good mimic of flood-front displacement (especially for water flooding projects), quick process, less fines migration, and they are less expensive than the steady-state experiment. Its disadvantages are due to the complicated interpretations and the non-equilibrium between the wetting and the non-wetting phases (Bennion and Thomas 1991) [12].

## Centrifuge Method

This method is done by rotating the plug at different velocities and the produced fluid is measured at every stage. From these stages, fluid saturations are calculated vs dimensionless time, from which relative permeability is calculated as introduced by (Haggort, 1980) [15]. There are many types of centrifuge experiments depending on the speed and acceleration of rotation, which are Single-speed, multi-speed, constant acceleration and constant flow rate. The main advantages of this method are:

- Eliminate fluid displacement instabilities
- Achieve high capillary pressures
- Fast and robust process
- Achieve high difference in pressure for low saturations

Disadvantages can be limited in:

- The need for numerical simulation in multi-speed tests
- Fines migration
- Water relative permeability cannot be defined in single speed tests

## Field background

In our case, we have field 'X' under study of water flood. After water flooding project has been started, field 'X' suffered from high water cut (W.C) rates in large oil producers, low oil production rates and as a consequence low recovery factor (RF). The water flood project was implemented based on a field development plan (FDP) that was issued in 2014 to target a recovery of 30% of original oil in place (OOIP). Problems have come to surface after reaching a recovery of 18%, when the water cut has increased in most wells and the recovery plan started to deviate to a worse scenario. The deviation from 2014 FDP urged a reconsideration of the study utilizing new methods and approaches with lowest cost to get the performance of the field on track again. As part of the study, a simulation model has to be built. This model should match the production performance of all phases (oil, gas water), to be countable for production forecast scenarios.

Core samples were collected from five wells 'X-2', 'X-3', 'X-4', 'X-5', 'X-6' and 'X-7'. Routine core analysis has been performed for all cores while Special Core Analysis (SCAL) was done over plugs extracted from well 'X-4'. After categorizing the relative permeability and capillary pressure data for five classes, the data had to be adjusted to get a history match for water producing wells.

## Results

### Permeability estimation:

Permeability was calculated based on the available core data in Field 'X' area for Abo Roash "G" (ARG) formation. A Porosity-Permeability relationship was established as shown in cross-plot in Figure 3. Three correlations were representing high, base and low cases for the pore-perm transform as in Table 1

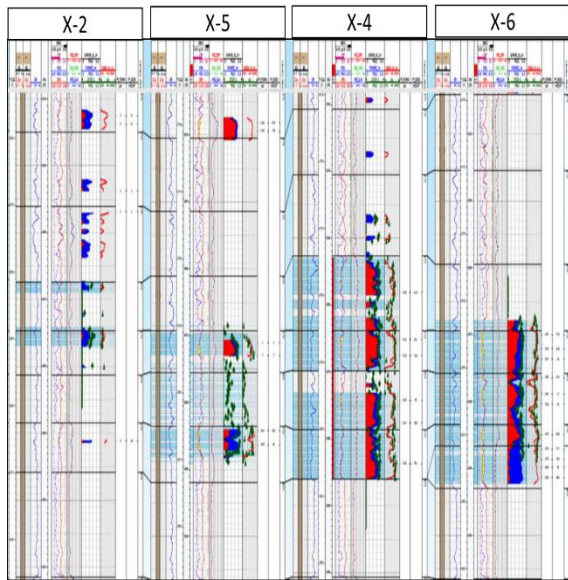


**Figure 3:** Core Permeability Vs. Stressed core porosity cross-plot

**Table 1:** Porosity-Permeability transform

Case	Pore-Perm Transform
High	$\text{Log}(\text{Perm}) = 26.93192 * \text{Por} - 3.41011$
Base	$\text{Log}(\text{Perm}) = 27.16861 * \text{Por} - 4.048714$
Low	$\text{Log}(\text{Perm}) = 27.56462 * \text{Por} - 4.907722$

The calculated permeability from Pore-Perm transform equations showed a good match with the measured core permeability showed in green-filled circles are core Permeability and red line represents the log-derived permeability calculated from Pore-Perm transform in last track as shown in Figure 4.

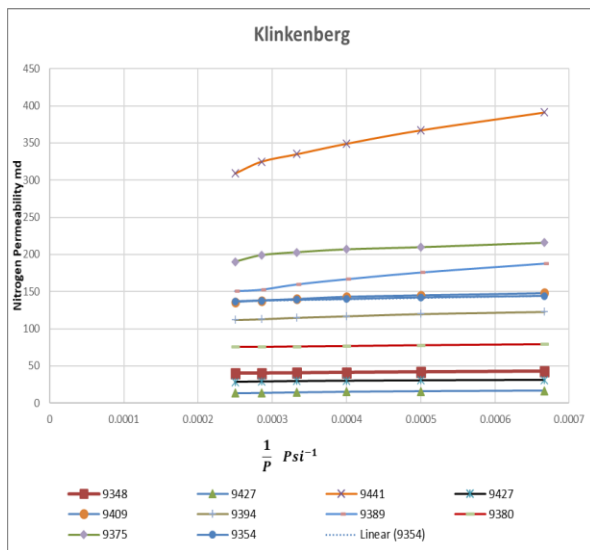


**Figure 4:** Comparison between calculated permeability from pore-perm transform and the measured permeability from cores

**Special Core Analysis (SCAL):**

Table 2 and

Figure 5.



The special core analysis performed for well ‘X-4’ over ten core samples from ARG formation and used in defining saturation height function from capillary pressure data and relative permeability curves. The results were categorized into five classes based on porosity ranges and connate water saturation.

**Relative permeability data:**

Relative permeability tests were performed using unsteady state technique. Average Relative permeability curves have been introduced and corrected for Klinkenberg effect as shown in

**Figure 5:** Relationship between permeability and effective pressure

Table 2: Measured Nitrogen Permeability

Sample	Depth	Nitrogen Permeability(md)								Calculated Liquid Permeability	
		Pressure	400	1000	1500	2000	2500	3000	3500		4000
		1/P	0.0025	0.001	0.000667	0.0005	0.0004	0.000333	0.000286		0.00025
R1	59	9348	45.8	44.3	43	42	41.3	40.7	40.3	40.1	38.34
R2	65	9354	150	146	144	142	140	139	138	137	133.24
R3	86	9375	240	227	216	210	207	203	199	190	182.23
R4	91	9380	83.1	81	79.5	78.2	77.1	76.5	76	75.9	73.53
R5	100	9389	211	196	188	176	167	160	153	151	128.87
R6	105	9394	132	127	123	120	117	115	113	112	105.74
R7	120	9409	158	152	148	145	143	140	138	136	130.24

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<b>R8</b>	138	9427	18.8	17.4	16.6	15.9	15.2	14.5	13.9	13.5	11.90
<b>R9</b>	150	9439	32.8	31.9	31.2	30.6	30.1	29.6	29.1	28.6	27.43
<b>R10</b>	152	9441	485	426	391	367	349	335	325	309	283.79

The relative permeability curves were categorized into five reservoir quality classes based on porosity ranges as in Figure 6 by the following classes:

- Class 1:  $\phi > 19\%$   $S_{WC} = 14.1\%$
- Class 2:  $19\% > \phi > 16\%$   $S_{WC} = 23.3\%$
- Class 3:  $16\% > \phi > 14\%$   $S_{WC} = 28.9\%$
- Class 4:  $14\% > \phi > 12\%$   $S_{WC} = 35.9\%$
- Class 5 :  $\phi < 12\%$   $S_{WC} = 47.7\%$

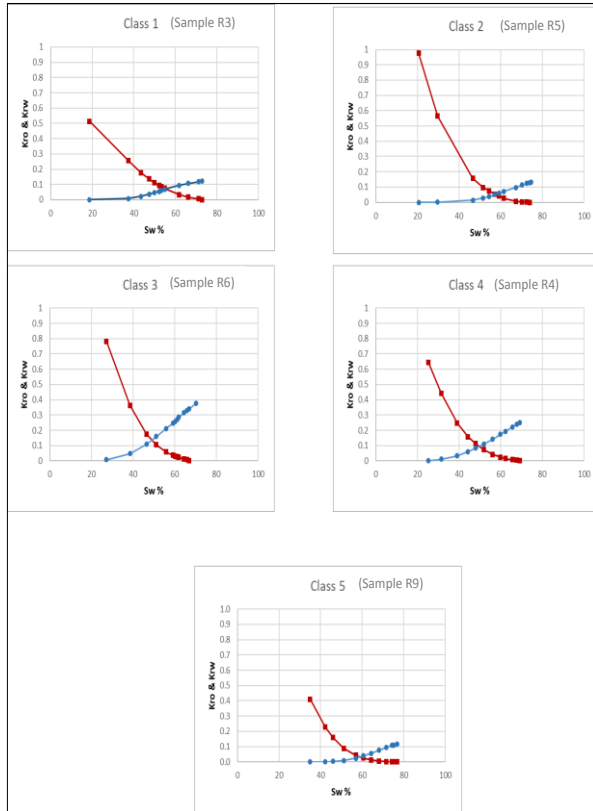


Figure 6: Relative permeability classes

Table 3: Relative Permeability Classes

Brine Saturation %	Kro	Krw
<b>Class 1 (Sample R3)</b>		
18.70	0.51	0.00
37.30	0.26	0.01
43.40	0.18	0.02
47.40	0.14	0.04
50.00	0.11	0.05
52.20	0.09	0.05
53.30	0.08	0.06
54.90	0.08	0.07

61.80	0.03	0.09
66.20	0.02	0.11
71.20	0.01	0.12
72.90	0.00	0.12
<b>Class 2 (Sample R5)</b>		
20.60	0.98	0.00
29.70	0.56	0.00
46.60	0.16	0.01
51.50	0.10	0.03
54.50	0.08	0.04
57.10	0.05	0.05
59.10	0.04	0.06
61.50	0.03	0.07
67.30	0.01	0.10
70.30	0.00	0.11
72.50	0.00	0.12
73.90	0.00	0.13
74.60	0.00	0.13
<b>Class 3 (Sample R6)</b>		
27.10	0.78	0.01
38.50	0.36	0.05
46.40	0.18	0.11
51.10	0.11	0.16
55.90	0.06	0.21
59.10	0.04	0.24
60.30	0.03	0.26
61.20	0.03	0.27
61.90	0.02	0.29
64.40	0.01	0.31
65.80	0.01	0.33
66.90	0.00	0.34
70.30	0.00	0.38
<b>Class 4 (Sample R4)</b>		
25.30	0.64	0.00
31.40	0.44	0.01
39.00	0.25	0.03
44.20	0.16	0.06

48.00	0.11	0.08
52.00	0.07	0.11
56.10	0.04	0.14
59.90	0.02	0.17
62.30	0.02	0.19
65.60	0.01	0.22
67.80	0.00	0.24
69.10	0.00	0.25
<b>Class 5 (Sample R9)</b>		
35.00	0.41	0.00
42.30	0.23	0.00
46.00	0.16	0.00
51.10	0.09	0.01
57.00	0.04	0.02
60.50	0.03	0.04
64.40	0.01	0.06
68.00	0.01	0.08
71.60	0.00	0.09
74.30	0.00	0.11
75.20	0.00	0.11
76.80	0.00	0.12

After introducing the five relative permeability classes into the simulation model, we could not achieve a good history match for production data especially for water production, which was a result of breakthrough, in most wells. Relative permeability end-points had to be manipulated as shown in Table 4 to match the water production history. This alteration in relative permeability showed a good match without multiplying any region of permeability with certain factors in reservoir as shown in Figure 7. The main cause of manipulation is that relative permeability samples were taken from only one well 'X-4', which was not enough for representing the whole reservoir heterogeneity.

**Table 4:** Manipulated Relative Permeability Data

Sw	Krw	Kro
<b>Manipulated Class-1</b>		
0.141	0	0.85
0.1415	9.49E-13	0.848
0.142	1.07E-11	0.847
0.1435	2.65E-10	0.842
0.1461	3.00E-09	0.835

0.1512	3.39E-08	0.82
0.1664	8.39E-07	0.775
0.1919	9.49E-06	0.703
0.2428	0.000107	0.569
0.2937	0.000444	0.447
0.3446	0.00121	0.339
0.3955	0.00265	0.244
0.4464	0.00502	0.163
0.4973	0.00861	0.0973
0.5482	0.0137	0.0469
0.5991	0.0207	0.0135
0.6245	0.0251	0.00387
0.6398	0.028	0.000743
0.6449	0.029	0.000214
0.6475	0.0295	6.13E-05
0.649	0.0298	1.18E-05
0.6495	0.0299	3.38E-06
0.65	0.03	0
1	1	0
<b>Manipulated Class-2</b>		
0.233	0	0.85
0.2334	9.49E-13	0.848
0.2338	1.07E-11	0.847
0.2351	2.65E-10	0.842
0.2372	3.00E-09	0.834
0.2413	3.39E-08	0.818
0.2539	8.39E-07	0.771
0.2747	9.49E-06	0.696
0.3164	0.000107	0.556
0.3581	0.000444	0.432
0.3998	0.00121	0.322
0.4415	0.00265	0.228
0.4832	0.00502	0.149
0.5249	0.00861	0.0863
0.5666	0.0137	0.0399
0.6083	0.0207	0.0107
0.6291	0.0251	0.00287
0.6417	0.028	0.000503
0.6458	0.029	0.000135
0.6479	0.0295	3.61E-05
0.6492	0.0298	6.33E-06
0.6496	0.0299	1.70E-06
0.65	0.03	0
1	1	0
<b>Manipulated Class-3</b>		
0.289	0	0.85
0.2894	3.00E-11	0.848
0.2897	2.40E-10	0.847
0.2908	3.75E-09	0.842

0.2926	3.00E-08	0.834
0.2962	2.40E-07	0.818
0.307	3.75E-06	0.771
0.3251	3.00E-05	0.696
0.3612	0.00024	0.556
0.3973	0.00081	0.432
0.4334	0.00192	0.322
0.4695	0.00375	0.228
0.5056	0.00648	0.149
0.5417	0.0103	0.0863

0.5778	0.0154	0.0399
0.6139	0.0219	0.0107
0.632	0.0257	0.00287
0.6428	0.0282	0.000503
0.6464	0.0291	0.000135
0.6482	0.0296	3.61E-05
0.6493	0.0298	6.33E-06
0.6496	0.0299	1.70E-06
0.65	0.03	0
1	1	0

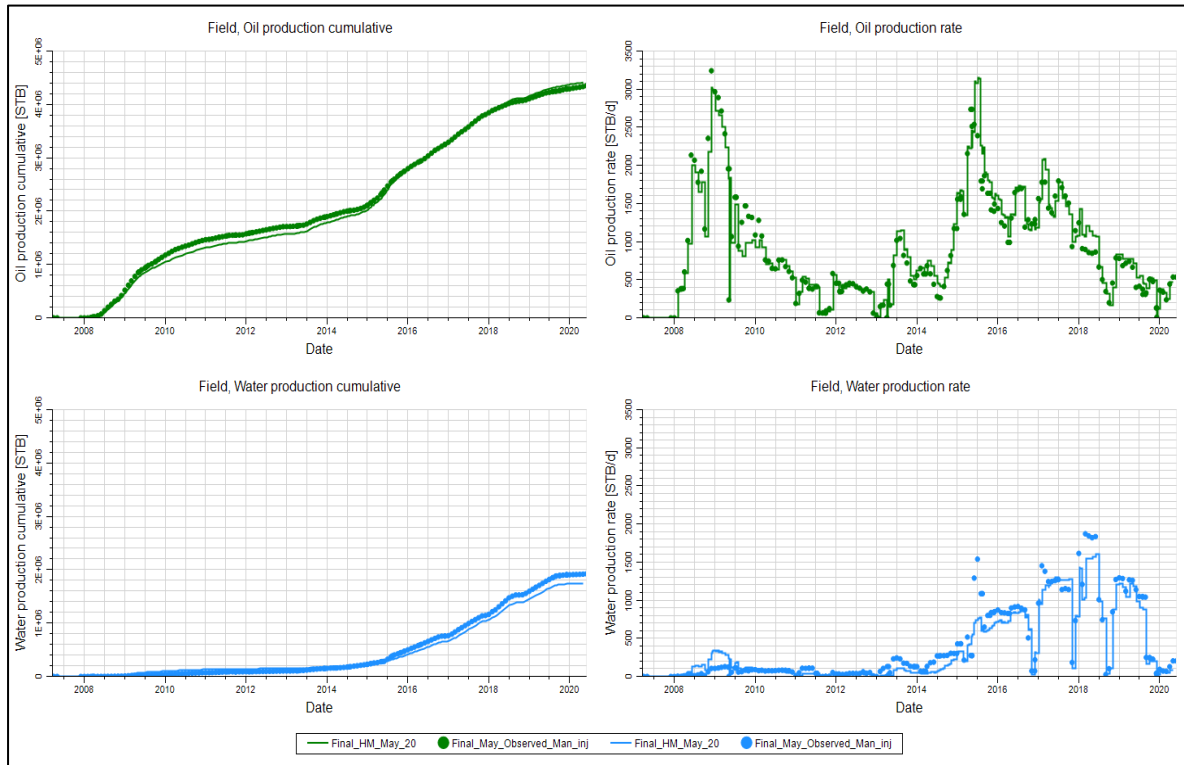


Figure 7: Field Simulation History Match

**Conclusions**

From these results, we can conclude the following:

- In our work we have shown that the direct use of relative permeability data from special core analysis may lead to difficulties in multi-phase flow history matching, which mandates the manipulation of relative permeability results to achieve the optimum history match of water and oil production rates. However, the relative permeability end point data shouldn't be changed dramatically to respect reservoir rock properties and saturation profiles.
- Relative permeability data obtained for a specific reservoir in a single well does not represent the whole reservoir because of reservoir heterogeneity.
- Taking as much core-plug samples for SCAL analysis as possible is vital for covering

differences in reservoir properties (as porosity and connate water saturation). This was beneficial in our case.

- Selecting the suitable method of relative permeability test in lab is important. The selection should respect the physical conditions and the actual displacement process in reservoir.

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This research received no external funding.

**Conflicts of interest**

There are no conflicts to declare.

**Nomenclature**

ARG	Abo Roash "G"
OOIP	Original Oil in Place
OIP	Oil in Place



W.C	Water cut
RF	Recovery factor
FDP	Field Development Plan
MMSTB	Million Stock Tank Barrel
BWPD	Barrel Water per Day
SCAL	Special Core Analysis
$S_{wc}$	Critical water saturation
$S_{or}$	Residual oil saturation
$k_{ro}$	Relative permeability of oil
$k_{rw}$	Relative permeability of water.

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