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Original article

The study of relative permeability and residual gas saturation at high pressures and high temperatures

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Abstract: This paper presents the results of laboratory investigation conducted with reservoir rock plugs recovered from the Gas reservoir in the North West Shelf of Western Australia. The experiments were conducted in reservoir conditions (High Pressure (HP = 41.37 MPa) and High Temperature (HT = 433.15 K)). The aim of this study was to determine residual gas saturation and quantify the effect of reservoir conditions (HP/HT) on gas-brine relative permeability. The experimental data have been analysed using relative permeability concept. Both wetting and nonwetting phase relative permeability were generated using explicit methods, i.e, Hasslar and Corey model (Power Model). The power model is then used to match experimental data through modifying the parameters of the Corey correlation. Several core plugs were used by this study representing different reservoir quality rocks in the reservoir. The core plugs were in different dimensions, the short core plugs measured around 5 cm in length while the long core plug measured 19.41 cm. The aim of using longer core plugs was to minimise the effect of capillarity and end-effects on the relative permeability measurements. Since permeability measurement under the test conditions depends on pressure drop across the core plugs.

Keywords: Core flooding experiment, porous media, petrophysical characterization, capillary pressure.

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1. Introduction

The modified Darcys law to describe the phase relative permeability concept was first suggested by Muskat and Meres (1936) and co-workers Wyckoff and Botset (1936). Relative permeability is commonly used to describe the multiphase flow of immiscible fluids in the porous media. The analysis of such complex flow in porous media has been presented in the form of Darcy-type equations (Sidiq et al., 2011). At a given phase saturation, fluid flow in porous media can be the function of several macroscopic transport properties, such as relative permeability and capillary pressure. These properties will be affected by fluid saturations, saturation history, fluid properties (viscosity, density and composition) and pore space morphology.

A survey of literature has been conducted and several studies were found on gas-brine relative permeability at high pressures and temperatures. Chen et al. (2014) studied CO_2-brine in a 61 cm long core sample at high pressures and ambient temperatures. They found that CO_2 end point relative permeability ranges from 0.4 to 0.8. Whilst Bennion et al. (2008) conducted a steady state relative permeability of super critical CO_2-brine and H_2S-Brine. Bennion found that brine residual saturation ranges from 20%-80% while residual gas saturation ranges between 10%-40%. Furthermore, Lee et al. (2009) studied CO_2-brine relative permeability in the temperature range 21-49 C and pressure range 500-1300 psi. They found that endpoint relative permeability increases monotonically with temperature whereas non-monotonically with pressure. Similarly, Bitao and Jennifer (2010) found with increasing pressure that the relative permeability of gas increases.

The composition of the injected phase was a mixture of methane and CO_2 in which methane comprised 90% while CO_2 only 10%. Under the imposed test conditions CO_2 is a super critical fluid. Sidiq and Amin (2010) have studied the

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Table 1. Petrophysical properties of the core plugs used in the experiments.

S.N.	Samples Code	Depth (m)	Length (cm)	Diameter (cm)	Area (cm^2)	K air (md)	Porosity (%)	Pore volume (cc)
1	SCA1	4,144.28	5	3.95	12.25	391	17.9	9.818
2	SCA2	4,160.68	2.05	3.89	11.89	115	14.1	7.958
3	SCA3	4,184.37	5.1	3.91	12.01	8.37	9.9	5.726
4	SV1	—	19.41	3.9	11.95	92	14.3	32.95

a-lithology factor, m-the cementation exponent (same definition with Archie law); Swi-irreducible (or connate) water saturation.

miscibility between CO_2-methane in terms of IFT and dispersion. A comprehensive study is presented on IFT between supercritical CO_2 and methane by Amin et al. (2010).

Experimental results from this study indicated that gas relative permeability is significantly influenced by temperature and pore pressure. On the other hand, other researchers found that the parameters that affect the relative permeability curve are a ratio between the viscous forces relative and capillary forces on the pore scale (Leverett, 1939; Bardon and Longeron, 1980; Ameafule and Handy, 1982; Boom et al., 1995; Henderson et al., 1996; Pope et al., 1998).

This paper presents the analysis of measured relative permeability in reservoir core plug samples at reservoir conditions (41 MPa and 433.15). The injection velocity was kept constant throughout the tests at 0.166 cm/min.

2. Experimental setup

The unsteady state experiment was adopted for gas-brine relative permeability investigation. Fig. 1 shows the details of the core-flooding rig units. The rig composed of several units including injection and collection unit, coreholder, backpressure regulator and air bath for temperature control. The injection speed measured at inlet and effluent of the coreholder.

Fig. 1. Photo of Core Flooding Rig at CGTA laboratory.

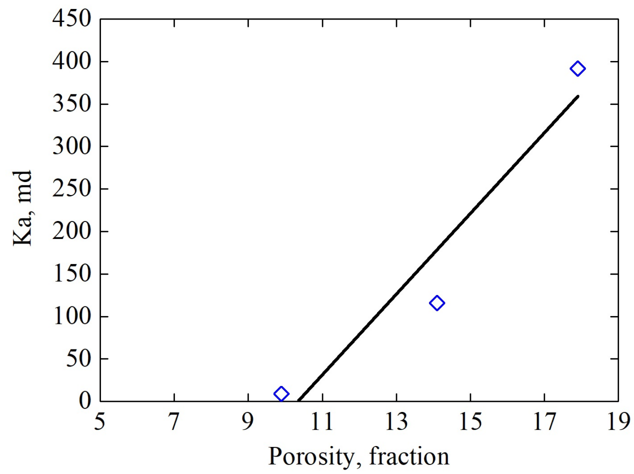

Fig. 2. Permeability and porosity relationship for the tested core samples.

The displacing were stored in titanium accumulators and connected to a syringe-pump. The temperature of injected fluids rose to reservoir condition temperature through using the concept of heat-transfer as the fluid passed in the stainless steel coils located inside the air bath chamber. Thus, the injected flu- ids are heated up to the desired temperature before flushing the core sample. The core holder, backpressure regulators and flow lines were housed inside a temperature-controlled, air-forced circulation oven.

The reservoir temperature was regulated by a high thermocouple while the differential pressure was instantly recorded using high precision pressure transducers digitally synchronized to a laboratory PC.

3. Reservoir core properties

The reservoir rock characteristics of the core plugs used by this study can be found in Table 1. It is apparent with increasing depth both permeability and porosity decrease. Fig. 2 shows a linear relationship between core samples absolute permeability and porosity.

4. Super CO_2-methane phase behaviour

The phase behaviour of binary methane-CO_2 and H_2O systems is crucial for understanding by which mechanisms gas displaces brine in reservoir conditions (HPHT). It is

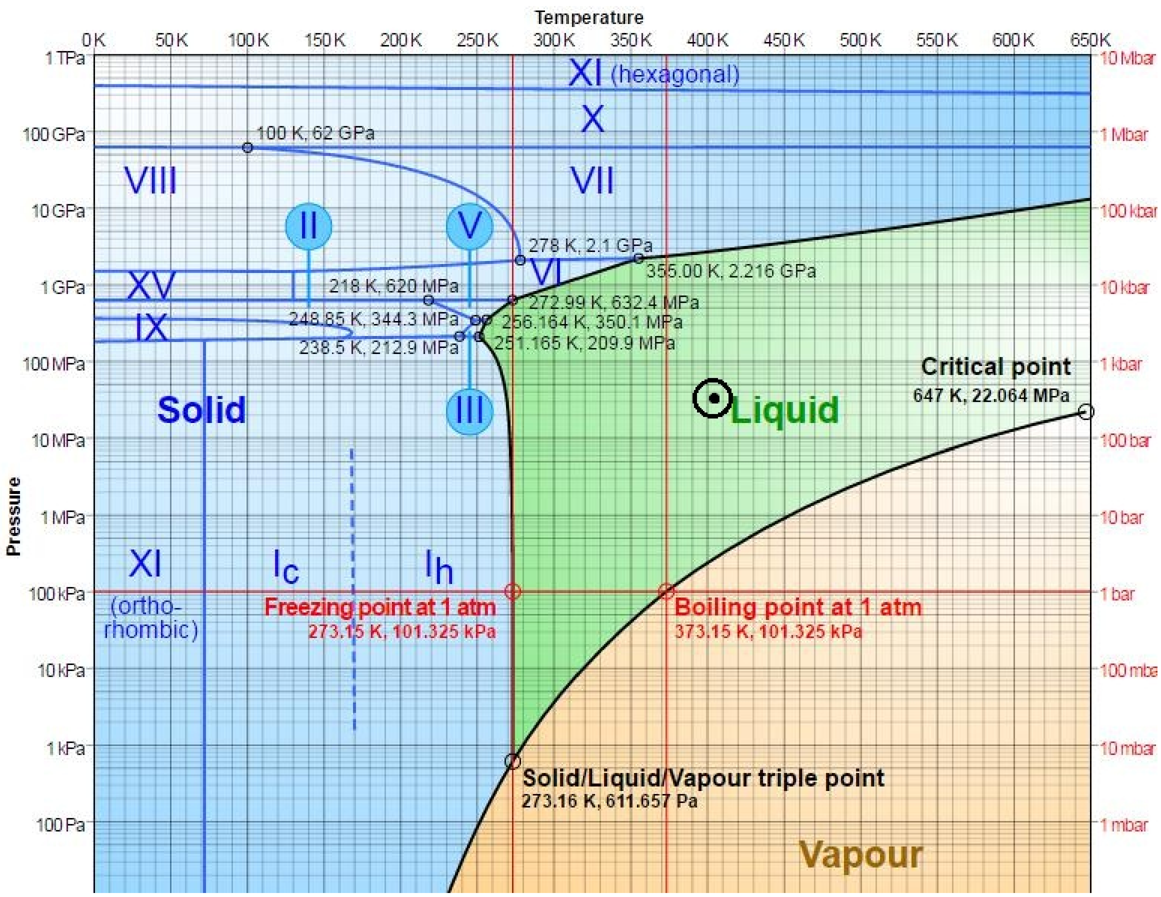

Fig. 3. Water phase behavior at different pressure and temperature (Martin, 2017). The (⊙), represent fluid state studied by this work. (http://www1.lsbu.ac.uk/water/water_phase_diagram.html)

known that CO_2 at a temperature of 304.15 K and pressure of 7.39 MPa is at super critical condition. Since CO_2 only represents 10% of the injected phase, the effect of CO_2 on the properties of displacing phase is minimal. Whereas CO_2 can be an effective agent when dissolved in water, it can alter permeability of the test core plugs, see Table 2. Obliviously, the long core sample (SV1) was greatly influenced by core flooding experiments with nearly 75% of its original permeability diminished.

Table 2. Dean Strak test result for all core plugs.

Sample No.	Before Ka (md)	After Ka (md)
SCA1	391	390
SCA2	115	104
SCA3	8.4	9.4
SV1	92.1	32.5

Fig. 3 shows the phase behaviour diagram for water. Under the test conditions (433.15 K and 41.37 MPa) the displaced phase (water) is at liquid phase while the injected is in gaseous phase which means injected phase immiscibly displaces the in situ water phase.

5. Test sequences and procedures

The core plugs were inserted into a viton Hassler sleeve and placed inside the core holder, evacuated and then saturated with connate water and flushed for more than 10PV before displacing it by methane (90% concentration with CO_2 making the remaining 10% as recommended by Shell Australia) to connate water saturation.

The composition of the produced gas was monitored online and on a continuous basis by a CO_2 gas analyzer (PEM tech gas analyser). The volume of produced gas is also measured by a flow meter.

The following sequence is applied throughout the tests:

• Stabilize temperature of air bath and equipment at 433.15 K for 24 hours.

• Measure permeability to air on clean, dry core samples. Ka

1. Saturate samples with 25,000 mg/ brine.

○ Measure water permeability at 100% brine saturation. Kw

2. Flush samples with Methane 90% to immobile water saturation,

○ Measure gas permeability at different gas saturation and immobile water saturation. Kg@Swi

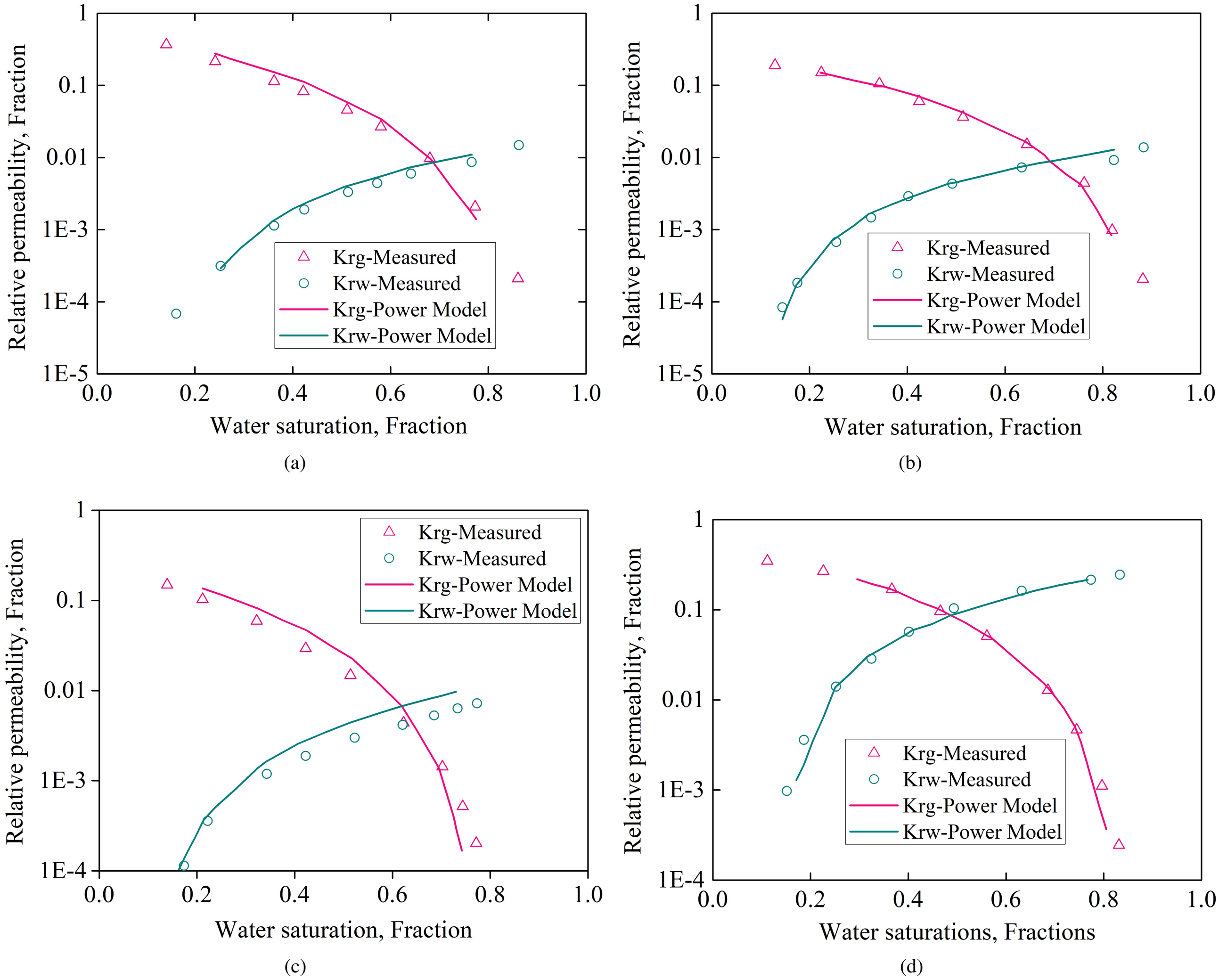

Fig. 4. Two phase gas-water relative permeability at reservoir conidtion. (a) Sample SCA1, (b) Sample SCA2, (c) Sample SCA3 and (d) Sample SV1.

6. Results and discussion

Before loading the core plugs into core holder the samples underwent cleaning and drying after the first set of tests in ambient condition. The air bath temperature increased to a reservoir temperature of 433.15 K and pressure to 41 MPa. The core plugs underwent the test sequences discussed in section 5. Figs. 4(a)-4(d) shows relative permeability curves for all tested core plugs. Under the reservoir conditions, relative permeability for the gas phase decreases with decreasing core samples permeability, see Fig. 5. This might be due to the internal pores distributions, mineral composition and heterogeneity.

The solid lines in Fig. 4 represent power model relative permeability curves and have been generated using Eqs. (1) and (2).

$$K_{rw} = K_{rw,max}\left(\frac{S_W - S_{wc}}{1 - S_{or} - S_{wc} - S_{gc}}\right)^{nw} \tag{1}$$

$$K_{rg} = K_{rg,max}\left(\frac{S_g - S_{gc}}{1 - S_{or} - S_{wc} - S_{gc}}\right)^{ng} \tag{2}$$

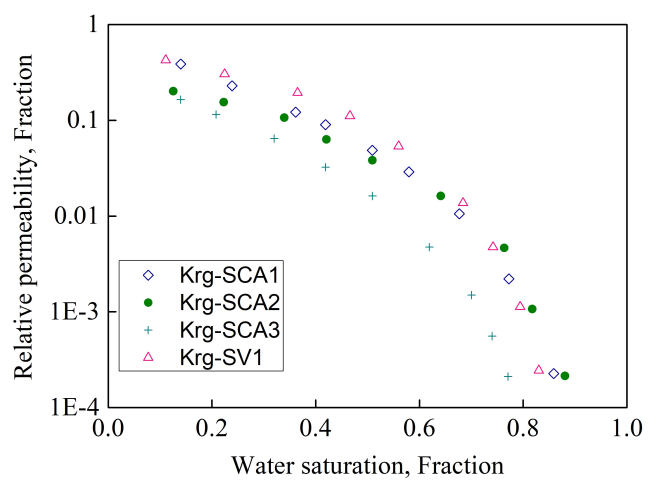

Fig. 5. Gas phase relative permeability for all tested core samples at reservoir conidtion.

Obviously, there is a good match between the calculated and measured relative permeability data for both the wetting and non-wetting phase.

However sample SCA3 (poor quality rock) did not show a good match between the calculated and measured relative permeability. This could be due to small pore size and distribution, different grain size and distribution, and clay content and distribution. Researchers such as Kerig and Watson (1987) have also noticed that a power relative permeability model cannot provide sufficient flexibility to reproduce the observed field results.

A point to be noted is that residual gas saturation under reservoir condition tests decreased for all core samples. The magnitude of matching parameter ng and nw ranges between 2.2-2.7 and 1.5-1.9, respectively.

Table 3. Residual gas saturation and matching parameter values (ng and nw).

S.N.	Samples Code	K air (md)	Sgc (%)	ng	nw (%)
1	SCA1	391	14	2.7	1.9
2	SCA2	115	12	2.2	1.7
3	SCA3	8.37	23	2.3	1.8
4	SV1	92	17	2.2	1.5

7. Conclusions

In this research work, relative permeability for gas-brine system is generated using explicit methods at reservoir condition of HPHT. A good match between calculated and measured relative permeability is observed. However the poor quality rock sample showed fair match between the calculated and measured relative permeability. This could be due to small pore size and distribution, different grain size and distribution, and clay content and distribution.

Although it is very costly to generate relative permeability curves for flowing phases in reservoir conditions, using power model to accurately predict reservoir condition relative permeability is very crucial in estimating reservoir performance correctly.

The proposed model in this research showed a good match between calculated relative permeability and experimental relative permeability measured in reservoir conditions.

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