

THIS IS A PREPRINT - SUBJECT TO CORRECTION

STEADY STATE BITUMEN- WATER RELATIVE PERMEABILITY MEASUREMENTS AT ELEVATED TEMPERATURES IN UNCONSOLIDATED POROUS MEDIA

BY

D. Brant Bennion, Hycal Energy Research Laboratories Ltd.
Gurk Sarioglu, Petro Canada Inc.
Mark Chan, Petro Canada Inc.
Toshiyuki Hirata, Japan Canada Oil Sands Ltd.
Dave Courtnage, Imperial Oil Ltd.
John Wansleeben, Canadian Occidental Petroleum Ltd.

PUBLICATION RIGHTS RESERVED

THIS PAPER IS TO BE PRESENTED AT THE CIM 1993 ANNUAL TECHNICAL CONFERENCE IN CALGARY, MAY 9-12, 1993. DISCUSSION OF THIS PAPER IS INVITED. SUCH DISCUSSION MAY BE PRESENTED AT THE TECHNICAL MEETING AND WILL BE CONSIDERED FOR PUBLICATION IN CIM JOURNALS IF FILED IN WRITING WITH THE TECHNICAL PROGRAM CHAIRMAN PRIOR TO THE CONCLUSION OF THE MEETING.

ABSTRACT

Accurate drainage and imbibition relative permeability data are essential for the accurate prediction of the performance of heavy oil reservoirs undergoing cyclic steam stimulation or steam drives. There is very little published data regarding steady state relative permeability measurements at elevated temperatures. This paper documents two complete water-bitumen steady state drainage and imbibition tests conducted at a temperature of 200°C at full reservoir pressure and overburden conditions utilizing composite core stacks of actual, preserved reservoir core material. The test results indicate substantial hysteresis effects in the non-wetting (bitumen) phase and provide insight into the wettability, displacement efficiency, residual saturations and endpoint permeabilities and relative permeabilities for an unconsolidated heavy oil sandstone reservoir.

INTRODUCTION

Relative permeability is an empirical parameter used to modify Darcy's single phase flow equation to account for the numerous complex effects associated with the flow of multiple immiscible

phases within porous media¹.

Relative permeability measurements are utilized extensively in many areas of reservoir engineering, and more particularly in recent years in the area of matching, predicting and optimizing reservoir performance and depletion strategies through the use of detailed numerical simulation models.

Those involved in numerical simulation realize the importance of good relative permeability data on the performance of reservoir simulation models. This paper discusses the generation of two complete sets of high temperature drainage and hysteresis relative permeability data.

FACTORS AFFECTING RELATIVE PERMEABILITY

Relative permeability can be affected by many physical parameters including fluid saturations,²⁻⁴ physical rock properties,⁵⁻⁷ wettability,⁸⁻¹⁰ saturation history (hysteresis effects),^{11,12} overburden stress,¹³⁻¹⁴ clay and fines content,^{15,16} temperature,^{17,18} interfacial tension,¹⁹ viscosity,²⁰ magnitude of initial phase saturations,^{21,22} immobile or trapped phases,^{21,22} and displacement rates and capillary outlet phenomena.²³⁻²⁶ A detailed discussion of the many factors affecting

designed for steady state displacements it was important to have both inlet and outlet sections of core on either side of the desired test section to absorb capillary effects and to ensure uniformly dispersed fluid flow into and out of the test section. This was accomplished utilizing internal pressure taps so that the pressure differential across the central test section, exclusive of the inlet and outlet sections, could be measured. The pressure tap line is run concentrically down the central bore of the injection line. This facilitates only having a single ported large bore tap for both the injection or production of fluid as well as for the measurement of pressure.

Stainless steel (316) sealing heads and nuts confine and seal the encasing lead sleeve preventing the influx of external annular core pressure into the core stack. The core material is retained through the use of specially fused sintered 300 mesh glass retaining disks which were specially manufactured for this project. The sintered glass retaining disks are placed at the injection and production ends of the core. These disks are in place to prevent the relatively plastic core material from being extruded from the core holder upon application of the annular overburden pressure but coarse enough to allow production of a wide size distribution of fines from the core material without plugging and blockage occurring. The disks also ensure smooth, well dispersed injection and production of fluids from the core. This mounting arrangement eliminates the need for gravel packs and facilitates mounting the cores with a minimum amount of core disturbance. The core pack is compressed hydraulically once mounted to eliminate capillary discontinuities between the individual plugs in the stack. The ductility of the sleeve material facilitates the application of a confining overburden pressure directly to the core material by pressurizing the annular space in the pressure vessel. The injection and production ends of the core heads are equipped with radial distribution plates to ensure that no areas of localized high velocity occur when injecting or producing fluids.

The pressure vessel is equipped with two separate internal heating systems controlled by ERD digital temperature controllers which are capable of elevating core temperature to 340°C. The pressure vessel is rated for 20.7 MPa at 340°C. The pressure jacket is equipped with an external electrically heat traced insulating jacket to minimize external heat losses at elevated temperature.

Pressure differential across the entire core is monitored through the use of two model DP15

Validyne pressure transducers. The transducers are connected in a manifold type arrangement, one having a range of 0 - 140 kPa while the second has a range of 0 - 1400 kPa. This arrangement facilitates the accurate measurement of both high and low pressure differentials which may occur over the course of a series of displacement tests. Both the low and high pressure transducers can be isolated should the pressure differentials in the system exceed their rated value. The transducer system is insulated and electrically heat traced (85°C) to ensure smooth transmission of pressure through the tubing to the transducers when heavy oil is present in the system. Visual gauges are also connected to the injection and production system from which the operator can take readings as a backup for the pressure transducer system. The transducers output to a digital display terminal from which the operator can obtain the instantaneous pressure differential. The transducers are calibrated prior to each run at run pressure using a set of highly accurate dead weight testers.

Another set of transducers identical to those described previously is located to measure the pressure differential across the center test section of the core under steady state flow.

Both oil and brine are displaced through the sample using a pair of highly accurate digitally controlled, variable speed, synchronous control positive displacement pumps. The pumps can inject at a range of speeds from 0.5 to 2000 cc/hr (0.008 to 33.33 cc/min) at pressures of up to 70 MPa with a 0.01 cc accuracy. The positive displacement type action of the pumps provides a very smooth and steady displacement minimizing velocity and pressure shocks to the core matrix.

Injection fluids are stored in 3.8 litre high pressure 316 SS storage cylinders. The system is designed so that either gas, brine or oil can be injected into the core material. Due to the high oil viscosity and the tendency of heavy oils to form emulsions with water or mercury when they are used as displacing fluids a high pressure 1000 cc 316 SS transfer piston is used to displace oil into the core. The transfer piston is heat jacketed and the injection line to the core heat traced to allow smooth flow of the heavy oil to the core sample. All oil is ultracentrifuged prior to use to remove any solids or water which can affect test pressure response.

Due to potential problems with sand production from unconsolidated samples a set of dual high pressure collection pistons is utilized on the production end of the core to collect the produced effluent. The pistons, transfer lines and production tubing are insulated and heat traced to allow smooth

temperature while under overburden pressure to allow uniform overburden pressure application.

4. Prepare system for run, activate heat tracing on all lines (approx. 85°C), injection pistons, production pistons. Heat core sample to mobilization temperature (approximately 80°C). Commence injection of clean dead oil to pressurize core to run operating pressure of 2000 kPa. Simultaneously increase overburden pressure to 6200 kPa, always maintaining at net 4200 kPa overburden pressure on the core material. Set backpressure regulator at 2000 kPa. Flood dead oil through core and confirm stabilized operation.
5. Slowly over an approximately 30 hour period, heat core material to test operating temperature of 200°C and maintain temperature at 200°C and pressure at 2000 kPa with 6200 kPa backpressure for all subsequent test steps. Continue to flow clean dead oil through the core stack. Once run temperature is achieved, determine permeability to clean oil at the irreducible water saturation.
6. Once initial stabilized oil permeability has been obtained, commence steady state co-injection phase #1 for the water saturation increasing phase of the test. Effect co-injection by switching to the injection of 80% clean oil and 20% injection water. Continue this co-injection process until:
 - a. Pressure differential across the test section stabilizes.
 - b. Samples of the effluent production indicate that the produced total fluid content is equivalent to the injected fluid ratios (i.e., 80% oil, 20% water).
7. Once a stabilized condition has been obtained, repeat step "6" but at a 60% oil, 40% water co-injection ratio.
8. Once a stabilized condition has been obtained, repeat step "6" but at a 40% oil, 60% water co-injection ratio.
9. Once a stabilized condition has been obtained repeat step "6" but at a 20% oil, 80% water co-injection ratio.
10. Once a stabilized condition has been obtained switch to 100% water injection. Flood to S_{or} , note final stabilized permeability to water at the

residual oil saturation.

11. Once the endpoint permeability to water at 200°C has been completed, the water saturation increasing phase of the test has been completed and the oil saturation increasing phase commences. Start the oil saturation increasing phase by switching to 20% oil - 80% water and co-injecting these two fluids until a stabilized differential pressure is obtained and a 20% oil - 80% water effluent ratio is obtained.
12. Once a stabilized condition has been obtained, repeat step "11" but at a 40% oil, 80% water co-injection ratio.
13. Once a stabilized condition has been obtained, repeat step "11" but at a 60% oil, 40% water co-injection ratio.
14. Once a stabilized condition has been obtained, repeat step "11" but at a 80% oil, 20% water co-injection ratio.
15. Once a stabilized condition has been obtained, switch to 100% clean oil injection and displace clean oil until no further water production (free or emulsified) is apparent. Determine final endpoint permeability to oil at the irreducible water saturation.

[Note: No "recycled" fluids were utilized in any phase of this test series. All fluids injected were either freshly cleaned oil (<1% BS&W) or clean synthetic reconstituted produced water].
16. Cool core to ambient temperature over a 36 hour period. slowly depressurize core to ambient pressure and bleed overburden pressure slowly to ambient. Dismantle apparatus and remove mounted core from the pressure vessel.
17. Freeze mounted core to facilitate dismounting. Remove lead confining sleeve and remove core "test sections" only for final extractive analysis.
18. Mount post test "test section" in thin lead sleeve with 300 mesh retaining screens. Subject to Dean Stark extraction to determine final residual oil and water saturations on a post test basis.

Once these measurements have been completed, measure Boyles Law porosity and extracted core air permeability.
19. Subject companion non tested samples of virgin core to saturation, porosity and permeability determination for comparative analysis to obtain pre-test values.

CONCLUSIONS

1. The use of preserved state core, reservoir fluids and the desired representative elevated temperature is necessary in order to obtain relative permeability data for elevated temperature pressures.
2. The configuration of the water-oil relative permeability curves, low endpoint permeability to water, high residual oil saturation and trapping phenomena resulting in a higher irreducible water saturation after testing would suggest water wet behavior at 200°C for both core tests.
3. Residual oil saturations ranged between 30 and 35% after waterflooding at 200°C indicating recoveries of approximately 65% of the oil in place by hot waterflooding. Steamflooding at 200°C, or at higher temperatures will likely result in a substantial additional reduction in residual oil saturation.
4. Substantial physical hysteresis was observed in the non-wetting (oil) phase in both tests. Much less hysteresis was observed in the water phase. Individual phase relative permeabilities were greater when their saturation was increasing than when decreasing.
5. At the temperature level tested (200°C) and the time duration studies (4-5 months/core) no significant evidence of thermally induced formation damage was apparent. Higher temperatures, longer exposure times and actual steamflood may result in a greater propensity for damage.
6. The in-situ formation of stable emulsions was observed in both tests.
7. The steady state methodology utilized generated consistent relative permeability results with good reproducibility between individual test runs.

ACKNOWLEDGMENTS

The authors would like to express appreciation to the management of Hycal Energy Research Laboratories Ltd., Petro Canada Inc., Imperial Oil Ltd., Canadian Occidental Petroleum Ltd. and Japan-Canada Oil Sands Ltd. for permission to publish this paper. We also acknowledge the generous support of CANMET in the partial funding of this project.

REFERENCES

1. Muskat, M., and Meres: M.W.: Physics, Vol. 7, (1936) 346.
2. Leverett, M.C. and Lewis, W.B.: "Steady Flow of Gas-Oil-Water Mixtures Through

Unconsolidated Sands," Trans., AIME, Vol. 142 (1941) 107.

3. Sarem, A.M.: "Three Phase Relative Permeability Measurements by Unsteady State Methods," SPEJ, Vol. 9 (1966) 199.
4. Owens, W.W. and Archer, D.E.: "The Effect of Rock Wettability on Oil-Water Relative Permeability Relationships," Trans, AIME, (July 1971) 873-78.
5. Maloney, D.R., Honarpour, M.M., Brinkmeyer, A.D.: "The Effects of Rock Characteristics on Relative Permeability," NIPER Report No. FC22-83 FE 60149 (January 1990).
6. Morrow, N.R.: "Capillary Pressure Correlation for Uniformly Wetted Porous Media," JCPT, (Oct. 1976).
7. Arps, J.J. and Roberts, T.G.: "The Effect of the Relative Permeability Ratio, the Oil Gravity and the Solution Gas-Oil Ratio on the Primary Recovery from a Depletion Type Reservoir," Trans., AIME, Vol. 24 (1955) 120.
8. Craig, F.F., Jr.: "The Reservoir Engineering Aspect of Waterflooding," SPE Monogram Series (1971).
9. Wang, F.H.L.: "Effect of Wettability Alteration on Water/Oil Relative Permeability, Dispersion, and Flowable Saturation in Porous Media," SPE Res. Eng. (May 1988).
10. Morrow, N.R., Lim, H.T., Ward, J.S.: "Effect of Crude Oil Induced Wettability Changes on Oil Recovery," SPE Form. Eval. (Feb. 1986).
11. Geffen, T.M., Owens, W.W., Parrish, D.R., and Morse, R.A.: "Experimental Investigation of Factors Affecting Laboratory Relative Permeability Measurements," Trans., AIME, Vol. 192, (1951) 99.
12. Land, C.S.: "Comparison of Calculated and Experimental Imbibition Relative Permeability," Trans., AIME, Vol. 251 (1971) 419.
13. Wei, K.K., Morrow, N.R., Brower, K.R.: "Effect of Fluid, Confining Pressure and Temperature on Absolute Permeabilities of Low Permeability Sandstones," SPE Form Eval. (August 1986).
14. Gobran, B.D., Brigham, W.E., Ramey, J.H. Jr.: "Absolute Permeability as a Function of Confining Pressure, Pore Pressure, and Temperature," SPE Form. Eval. (March 1987).
15. Soeder, D.J.: "Laboratory Drying Procedures and The Permeability of Tight Sandstone Core,"

Sandstone Reservoirs", SPE 23783, Presented at the SPE Formation Damage Symposium Lafayette, Louisiana (Feb. 26-28, 1992).

41. Bennion, D.W., Moore, R.G. and Thomas, F.B.: "Effect of Relative Permeability on the Numerical Simulation of the Steam Stimulation Process," The Journal of Canadian Petroleum Technology, (March/April 1985), p. 40.

TABLE 3
HIGH TEMPERATURE STEADY STATE
RELATIVE PERMEABILITY STUDY
TESTS #1 AND 2 - CORE AND RUN PARAMETERS

	Test #1	Test #2
Length (cm)	32.4	34.5
Diameter (cm)	3.81	3.81
Effective Flow Area (cm ²)	11.40	11.40
Porosity (%)	38.0	39.1
Bulk Volume (cm ²)	369.36	393.3
Pore Volume (cm ³)	140.36	140.36
Water Viscosity at 200 ^o C (mPa.s)	0.134	0.134
Oil Viscosity at 200 ^o C (mPa.s)	7.8	7.8
Test Temperature (°C)	200	200
Backpressure (kPag)	2000	2000
Overburden Pressure (kPag)	6200	6200
Initial Permeability to Oil (μm ²) x 10 ⁻³	1544.6	1491.94
(mD)	1565.0	1511.60
Air Permeability (μm ²) x 10 ⁻³	2500.0	2701.1
(mD)	2533.0	2736.6

TABLE 4
HIGH TEMPERATURE STEADY STATE
RELATIVE PERMEABILITY STUDY
TEST #1 - WATER SATURATION INCREASING TEST RESULTS

Saturations		Permeability to Oil		Permeability to Water		Kro	Krw
S _o	S _w	μm ² x 10 ⁻³	(mD)	μm ² x 10 ⁻³	(mD)		
0.942	0.058	1544.6	1565.0	0.00	0.00	0.8000*	0.0000
0.911	0.089	1191.9	1207.6	1.71	1.73	0.6173	0.0009
0.819	0.181	330.7	335.1	3.65	3.70	0.1713	0.0019
0.759	0.241	221.9	224.9	5.52	5.59	0.1150	0.0029
0.695	0.305	120.3	121.9	7.98	8.08	0.0623	0.0041
0.311	0.689	0.00	0.00	120.62	122.21	0.0000	0.0625

* K_{abs} estimated to be 1930.80 x 10⁻³ μm² [1956.3 mD] using the assumption that k_o = 0.80 k_{abs}

TABLE 5
HIGH TEMPERATURE STEADY STATE
RELATIVE PERMEABILITY STUDY
TEST #1 - WATER SATURATION DECREASING TEST RESULTS

Saturations		Permeability to Oil		Permeability to Water		Kro	Krw
S _o	S _w	μm ² x 10 ⁻³	(mD)	μm ² x 10 ⁻³	(mD)		
0.311	0.689	0.00	0.00	120.62	122.21	0.0000	0.0625
0.591	0.409	232.3	235.4	15.38	15.58	0.1203	0.0079
0.667	0.333	340.8	345.3	9.87	10.00	0.1765	0.0050
0.722	0.278	477.1	483.4	5.26	5.33	0.2471	0.0027
0.794	0.206	755.8	765.8	3.31	3.35	0.3915	0.0017
0.861	0.139	1299.2	1316.3	0.00	0.00	0.6729	0.0000

FIGURE 1
HYCAL HIGH TEMPERATURE
STEADY-STATE RELATIVE PERMEABILITY APPARATUS

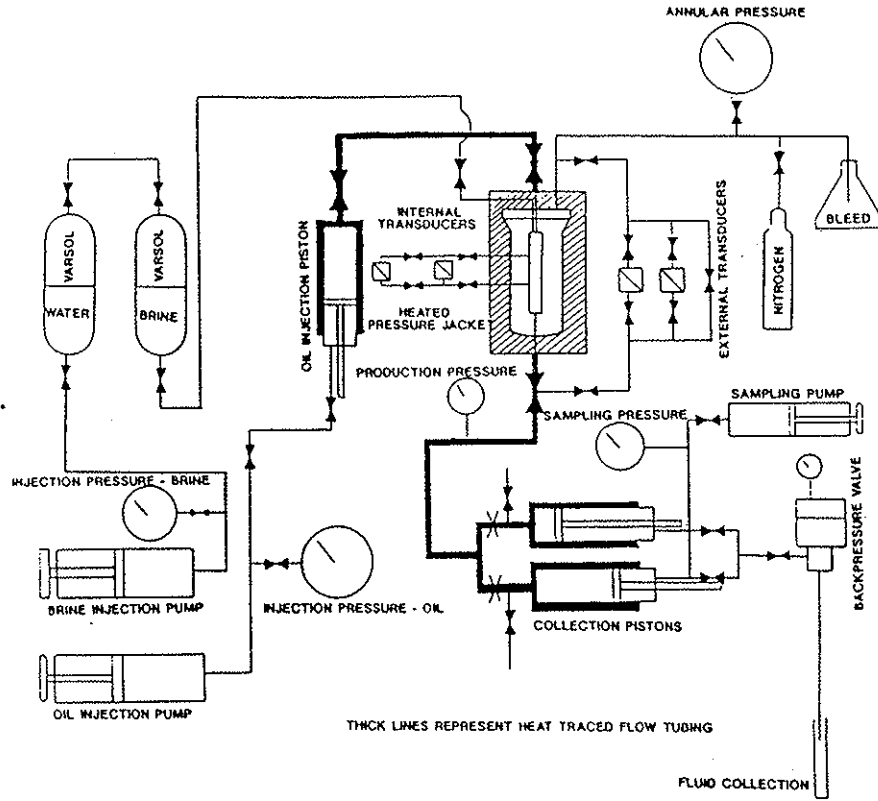


FIGURE 2
HIGH TEMPERATURE STEADY-STATE FLOW STUDY
COREHOLDER SCHEMATIC

