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Abstract

Waterflooding is by far the most widely used method in the world to increase oil recovery. Historically, little consideration has been given in reservoir engineering practice to the effect of injection brine composition on waterflood displacement efficiency or to the possibility of increased oil recovery through manipulation of the composition of the injected water. However, recent work has shown that oil recovery can be significantly increased by modifying the injection brine chemistry or by injecting diluted or low salinity brine.

This paper reports on laboratory work done to increase the understanding of improved oil recovery by waterflooding with low salinity injection water. Porous media used in the studies included outcrop Berea sandstone (Ohio, U.S.A.) and reservoir cores from the Green River formation of the Uinta basin (Utah, U.S.A.). Crude oils used in the experimental protocols were taken from the Minnelusa formation of the Powder River basin (Wyoming, U.S.A.) and from the Green River formation, Monument Butte field in the Uinta basin.

Laboratory corefloods using Berea sandstone, Minnelusa crude oil, and simulated Minnelusa formation water found that at lower aging temperatures, very little to no additional oil was recovered from low-salinity corefloods compared to full-strength reservoir brine floods; while higher aging temperatures resulted in significantly higher recoveries from low-salinity floods than from full-strength reservoir brine floods. Waterflood studies using reservoir cores and fluids from the Green River formation of the Monument Butte field also showed significantly higher oil recoveries from low salinity waterfloods with cores flooded with fresher water recovering 12.4% more oil on average than those flooded with undiluted formation brine.

Introduction

Different wetting states of crude oil, brine, and rock ensembles can yield widely different oil recoveries during laboratory waterflood tests (Jadhunandan and Morrow 1995). The wettability of a rock and fluids system can be altered in a number of ways: for example, changing crude oil composition, changing the aging temperature of the rock with crude oil, or by changing the temperature of displacement (Jadhunandan and Morrow 1995). The initial water saturation has a dominant effect on the wettability states induced by adsorption from crude oil because the distribution of water determines which parts of the rock surface are contacted by the oil (Salathiel 1973; Xie and Morrow 2001; Tong et al. 2002). It has also been observed that brine composition could have a significant impact on oil recovery (Yildiz et al. 1999; Tang and Morrow 1997). It follows that there may be cases where attention to brine composition could lead to increased oil recovery and greater economic profitability of a waterflood.

At the start of a waterflood, water from the cheapest source (usually different in composition to the formation water) is used as the injection water, provided injectivity is not adversely affected by formation damage. Historically, little consideration has been given in reservoir engineering practice to the effect of injection brine composition on waterflood displacement efficiency or to the possibility of increased oil recovery through manipulation of the composition of the injected water. Most laboratory relative permeability tests and displacement tests are done using synthetic formation water as both the connate and injected brine rather than using formation connate brine and the actual field injection water.

There may be many possibilities for improving oil recovery by manipulation of the injection brine chemistry, but dilution of the injection brine appears the most promising with respect to near term field application. Several examples of improved recovery by injection of low ionic strength brine have been reported for both outcrop and field core samples (Tang and Morrow 1997; 2002; Boussour 2009; Alotaibi et al. 2010) and for field applications (McGuire et al. 2005). Tang (1998) showed three conditions were necessary for increased recovery: 1) the crude oil must contain polar compounds that can be adsorbed on onto the rock surface, 2) clay must make up a portion of the rock, and 3) the water saturation must be greater than zero.

Robertson et al. (2003) demonstrated that not every crude-oil/brine/rock (COBR) system is amenable to low-salinity flooding and that great care should be taken when selecting rock used for experimentation. They experimented with two well-studied COBR systems previously shown in the laboratory to recover more oil from low-salinity waterflooding than using connate water.

However, they were not able to replicate previous results because the clay in the sandstone samples they used, which is essential for oil release, was apparently damaged or deactivated during years of storage at an elevated temperature of 55°C.

The objectives of the work reported in this paper are to test for improved recovery for a wider range of crude oil/brine/rock systems than previously used, identify target reservoirs for field testing, and improve our understanding of the mechanisms that cause sensitivity of oil recovery to brine composition. The work progressed from studying the scalability of low-salinity flooding using a COBR system known for its sensitivity to low-salinity waterflooding, to identifying conditions under which low-salinity waterflooding may increase oil recovery from two additional basins (Powder River and the Uinta basins) where waterflooding is common.

Core and Fluids Preparation. Some of the corefloods were done using Berea sandstone[1] while others were done using plugs cut from downhole field cores. Prior to fluid flow experiments, all cores were coated with epoxy[2] (see Figure 1**)**. Stainless steel fittings were permanently embedded into the epoxy to provide injection and production ports. The non-sag epoxy paste used to coat the cores penetrated the core to a depth of no more than one or two sand grains. The penetration depth, although very small, was taken into account when measuring core bulk volumes. Epoxy was applied to a thickness of about ¼ inch around the sandstone cores, which provided enough confining strength to withstand injection pressures up to 100 psig. By this method, the cores were effectively sealed, allowing no fluid flow around the outside of the core. Using this methodology, any number of cores could be in various stages of preparation and flooding without the need to purchase multiple and expensive Hassler-type core holders. While some epoxy resins can affect imbibition and wetting phenomena, no change in wetting behavior was detected for the epoxy used in these experiments. Cores from blocks of Berea sandstone and plugs from field cores were both cut parallel to bedding planes.

After a core was cut using tap water, dried at 55°C for two to three days, and coated in epoxy, the mass of the dry core was recorded and gas permeability was measured using carbon dioxide (CO_2) gas as the flowing fluid. Permeability to gas was measured at various flowing pressures. The gas permeability data were extrapolated to infinite pressure to account for the Klinkenberg effect and to obtain the effective gas permeability. Epoxy-coated, CO_2-saturated cores were then placed in a sealed chamber under vacuum for ½ hour prior to submersion (still under vacuum) by degassed brine. The vacuum was held on the submerged core for two additional hours and then released. The cores remained in the brine saturation chamber submerged in water under atmospheric pressure overnight and were removed and sealed by capping the injection and production ports. A minimum of five pore-volumes of water were injected through the cores with 60 psi backpressure while water permeability was measured. If any CO_2 remained inside the core after vacuum saturation, it would be more readily dissolved in the displacing water than a less soluble gas and be transported from the core during the water permeability measurements. The mass of the water-saturated core was recorded and the core pore volume (V_p) was calculated by:

$$V_p = \frac{m_w - m_d}{\rho_w} - V_e,$$

where m_w is the mass of the water saturated core, m_d is the mass of the dry core, ρ_w is the density of the saturating water, and V_e is the dead volume at the ends of the core (see Figure 1). The dead volume is small, yet significant and should be taken into account when the pore volume is calculated. Porosity is calculated by dividing the pore volume by the measured bulk volume.

Crude oil used in laboratory corefloods was filtered to remove any particulate matter and then placed under a vacuum and stirred for one hour at room temperature to remove soluble gasses from the oil. All cores were oil-flooded at a differential pressure drop of 50 psid. Five pore volumes of oil were injected in each direction while collecting the produced water. The volume of the produced water was quantified and used to determine the oil and water saturations after the oil flood by the following equations.

$$S_w = 1 - \left(\frac{V_w - V_e}{V_p}\right)$$

and

$$S_o = 1 - S_{wi}$$

where S_w is the water saturation, V_w is the volume of the produced water, and S_o is the oil saturation. The cores were then aged at the selected aging temperature[3] in order to accelerate the stabilization of the wetting state at residual water saturation. However, before the cores were placed in the aging oven, one end was capped and on the other end an 18-in. (46-cm) piece of capped nylon

[1] Cleveland Quarries, Amherst, Ohio.
[2] Hysol brand epoxy 1C purchased from Krayden Inc. Denver, Colorado.
[3] See discussion on specific experiments later in the paper for details on the aging temperatures used.

tubing was attached that was half-filled with crude oil to allow for fluid expansion without building up high pressure within the core as the fluids warmed. The cores were aged at the desired temperature for 10 to 18 days, after which they were considered to be at stable initial conditions and ready for waterflooding.

Experiments with CS Crude Oil. A COBR ensemble consisting of CS crude, CS reservoir brine (CSRB), and Berea sandstone was selected for initial tests to develop laboratory protocols because of the positive results obtained by Tang and Morrow (1999) in demonstrating the effectiveness of low-salinity waterflooding with this COBR ensemble. Procedures and methods used with this system were applied to other COBR ensembles to enlarge the envelope to new COBR systems that have potential for low-salinity waterflooding.

Four Berea sandstone cores (see Table 1 for core properties) were prepared and brought to initial conditions using CS crude oil. The cores were freshly cut from a block stored at room temperature (70°F [21.1°C]). Connate brine for two of the cores was undiluted CSRB and the connate brine for the other two cores was a one hundred-fold dilution of CS reservoir brine (0.01 CSRB).

After oil saturation, the cores were aged at 131°F (55°C) and waterflooded at the same temperature. In these cores, the injection brine was the same as the connate brine. Results for all the cores used in this set are plotted in Figure 2. The average recovery from the cores flooded with low-salinity brine cores (61.5% OOIP) was significantly higher than that for the cores flooded with full strength reservoir brine (52.5% OOIP).

Corefloods with Minnelusa Oil. Laboratory corefloods were performed to study the effects of injection brine dilution with Minnelusa crude oil. Minnelusa crude oil is an asphaltic crude with very little waxy components (Thomas et al. 1991). All the cores in the experiments with asphaltic Minnelusa crude oil were initially saturated with full strength Minnelusa reservoir brine (MRB) such that the connate brine for all the cores was full strength MRB. Some cores were flooded with diluted MRB and others flooded with full strength MRB. Early tests were done at room temperature and later tests were done at the reservoir temperature of 167°F (75°C).

Minnelusa Corefloods at Room Temperature. Room temperature was selected as the flooding temperature because it simplifies the flooding process as an oven (or other temperature control device) would not be required. The objective of this series of corefloods was to establish a baseline for increased oil recovery using diluted formation brine as the injection brine compared to full strength reservoir brine. Table 2 lists the measured permeabilities, porosities, and initial water saturations for the eight cores cut from a Berea sandstone block. After the cores were cut from the block, they were dried at 131°F (55°C) for 3 days, then cooled and coated with epoxy. All the cores were initially saturated with synthetic MRB with composition shown in Table 3. Total dissolved solids (TDS) content of reservoir brine was 38,653 ppm and the pH of the solution was 6.85. The cores were then oil flooded and aged at a typical Minnelusa reservoir temperature of 131°F (55°C) in a sealed pressure vessel. After aging, the cores were removed from the oven and allowed to equilibrate at the 70°F (21.1°C) ambient temperature of room. With the cores at room temperature, one pore volume of fresh crude oil was injected through the core before the waterflood.

Four of the cores were waterflooded with MRB and the other four cores were waterflooded with a 100-fold dilution of MRB (0.01 MRB), all at room temperature, with no applied backpressure, and at a constant flow rate of 3 ft/D. Figure 3 shows the results of the room temperature waterfloods with Minnelusa crude in Berea sandstone. Oil recoveries for all eight waterfloods ranged from a low of 38.6% OOIP to a high of 45.4% OOIP. The average recovery of the low-salinity waterfloods was 42.0% ± 2.8 OOIP while the average recovery for the undiluted floods was 41.1% ± 1.5 OOIP. There was no significant difference in oil recovery seen between the reservoir-brine injection set and the low-salinity injection set.

Differential pressure recorded for the floods, however, was significantly higher for the diluted waterfloods. The higher differential pressures of the low-salinity floods presumably resulted from clay swelling or detachment and subsequent pore blockage (Civan, 2007). Higher differential pressures did not result in higher oil recoveries.

The low-salinity floods were expected to produce higher recoveries, but did not under these circumstances. Several factors may have contributed to this result. The relatively low flooding temperature (70°F) may have been too low to induce the wetting change necessary to increase recovery or the aging temperature (131°F) may have been too low for this particular COBR ensemble. Additionally, the high mobility ratio of the waterflood caused by the relatively low temperature (ambient) may have masked the expected increase in oil recovery from the diluted waterfloods. Further tests at a representative reservoir temperature of 167°F (75°C) were planned to promote greater wetting changes during the aging and waterflooding processes and to lessen the possibility of viscous fingering during waterflooding.

Minnelusa Corefloods at 167°F (75°C). Seven 3-in. cores (1.5 in. in diameter) cut from Berea sandstone were used in a set of experiments with Minnelusa crude oil. Gas permeabilities of the cores ranged from 88 to 151 md for this set of cores and were comparable to the cores used for the room temperature waterfloods. Table 4 lists the properties of the cores at initial waterflooding states. The cores were aged at 167°F (75°C) inside a forced-air, water-cooled oven. Prior to beginning the waterfloods, one pore volume of fresh Minnelusa crude oil was injected through the core. No produced water was detected from any of the cores during this step.

Either full strength MRB or diluted MRB (100-fold dilution) was injected into the cores at 167°F (75°C) at 3 ft/D. The water reservoir was located outside the oven, the cores were inside the oven, and the effluent collection tubes were located outside the oven. The production line (from the core to the collection tubes outside the oven) was as short as possible and made out of 1/16-inch stainless steel tubing in order to minimize fluid hold-up in the line. No oil was found in the production line after the waterflood for any of the cores in this set of tests.

No backpressure was used during the waterfloods. A transducer connected to a computer provided a record of the differential pressure across the core. The oil and water produced during the waterflood was collected in 15 mL tubes in a fraction collector outside the oven. The waterflood was continued until 10 pore volumes were produced. The dead-volume oil was subtracted from the oil produced in the first collection tube. Because the cores were at the reservoir temperature (T_R) of 167°F (75°C) during the waterflood, the fluid densities used to quantify initial oil in place and production volumes were calculated at T_R. Both oil density and water density were corrected from room temperature to 167°F (75°C) according to the methods outlined in Prats (1982).

All the cores flooded with the low-salinity brine (a 100-fold dilution of MRB) had higher recovery factors than the cores flooded with full strength MRB. Figure 4 shows the average oil recovery curves for the low-salinity waterfloods versus the undiluted waterfloods. The recovery and differential pressure data shown in Figure 4 for the low-salinity floods consist of the average of all five low-salinity floods, while the data for the undiluted floods consists of the average of the two undiluted floods. The average recovery factor for the low-salinity waterfloods was 55.7% compared to an average recovery factor of 49.0% for the undiluted waterfloods. Earlier tests (see Figure 3) with the COBR ensemble aged at 131°F (55°C) and flooded at room temperature showed no increase in recovery from low-salinity floods; but recovery from low-salinity floods is clearly higher (13.7% higher) when aged and waterflooded at the higher temperature of 167°F (75°C).

Monument Butte Field Corefloods. The Monument Butte field produces a high wax content crude oil with a pour point of 95°F (35°C) and is currently under a field waterflood. Potable water is available as a source of injection water and Inland Resources Inc., operators of the field, were interested in the applicability of dilute waterflooding to the Monument Butte field to increase oil recovery during waterflood operations.

Depositional Environment and Reservoir Description. The Monument Butte field is located in the Uinta Basin. The Uinta Basin is a topographic and structural trough encompassing an area of more than 9300 mi^2 in northeast Utah (Utah Geological Survey 2000). The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank. The Uinta Basin formed in Paleocene to Eocene time, creating a large area of internal drainage that was filled by ancestral Lake Uinta. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial red-bed deposits, which are laterally equivalent to and intertongue with the Green River Formation, make up the Colton Formation (Wasatch).

More than 450 million barrels of oil have been produce from the Green River and Colton Formations in the Uinta Basin. The Cedar Rim, Altamont, Bluebell, and Red Wash fields produce from the northern shoreline deposits of Lake Uinta, while the fields in the Monument Butte area produce from southern deltaic shoreline deposits as preserved in the Middle and Lower Members of the Green River. The southern shore of Lake Uinta was very broad and flat, which allowed large transgressive and regressive shifts in the shoreline in response to climatic- and tectonic-induced rise and fall of the lake. The cyclic nature of Green River deposition in the Monument Butte area resulted in numerous stacked deltaic deposits. Distributary-mouth bars, distributary channels, and near shore bars are the primary producing sandstone reservoirs in the area. The Lower Douglas Creek sandstone and the D sandstone of the Green River formation are the more important reservoir units in the greater Monument Butte field.

Water Analyses. Produced water was collected from a number of wells in the field. The total dissolved solids (TDS) of these water samples ranged from 9116 ppm to 14,532 ppm; the average being 11,780 ppm. An analysis of the formation water is shown in Table 5. The synthetic formation water recipe (see Table 6) used in the laboratory corefloods is based on an average of seven produced water analyses.

Three different field injection water analyses were also obtained. The field injection water for the ongoing waterflood is fairly fresh. The concentration of TDS of the injection water ranges from 402 ppm to 729 ppm with the average being 583 ppm. The average injection water analysis is shown in Table 7, while the composition of the synthetic injection water is shown in Table 8.

Oil and Core Preparations. Crude oil and water samples were collected simultaneously from a number of wells from the Monument Butte field at the same time as the water samples were collected. However, all oil used in the corefloods was collected from the same well: Monument Butte 3A-35. The oil was heated to the reservoir temperature of 140°F (60°C), filtered to remove any particulates, and placed under vacuum for one hour to remove light ends and reduce the possibility of gas coming out of solution during coreflooding. The filtered and degassed oil was then placed in a capped bottle and stored in an oven at 140°F (60°C) for short-term storage.

A series of laboratory corefloods were done to evaluate the process of low-salinity water injection to improve waterflood recovery for the Monument Butte field. Because of this crude oil's a high pour point (95°F), all oil-handling and corefloods were done in an oven at the reservoir temperature of 140°F (60°C) instead of initial tests at ambient room temperature. All the cores were initially saturated with synthetic Monument Butte formation brine and then flooded with Monument Butte crude oil to establish the initial oil saturation (S_{oi}) and connate water saturation (S_{wc}) with no gas saturation. The cores were then stored in the 140°F oven at for at least two weeks to allow the wetting state to stabilize. Figure 5 is a schematic diagram showing the laboratory setup used when waterflooding the cores using Monument Butte formation fluids.

Coreflooding with Monument Butte Crude Oil. Initial experiments were done using Berea sandstone cores. Later floods were done using field core plugs. Initial and produced volumes of oil and water were calculated at flooding temperature (140°F). Waterfloods were run at a maximum of 3 ft/D or 60 psid. Produced oil was quantified by measuring the volume collected in the produced oil trap, and the water was back-calculated from the weight of the produced water collected outside the oven. Produced water volume was calculated from its mass and density at 140°F (60°C).

Berea Sandstone Cores. Two cores, A28 and A29, were prepared from the Berea sandstone block. Permeabilities and porosities of the two cores are shown in Table 9. Results using Berea sandstone, Monument Butte crude oil, and simulated reservoir and injection brine were primarily meant to work out waterflooding procedures before using field core. The water injection rate was set at 3 ft/day for the Berea sandstone cores. The results of the corefloods are shown in Figure 6. The waterflood oil recovery was 32.7% OOIP for the core using reservoir brine as the injection water. For the low-salinity coreflood, the oil recovery was 34.9% OOIP. The percent increase in recovery of 6.8%, which is not a large difference, but the work with Minnelusa crude oil (discussed earlier in this paper) suggests that the flooding temperature of 140°F (60°C) might have been too low to see a significant increase in recovery from low-salinity flooding when using Berea sandstone as the reservoir rock and the decision was made to proceed with the field core trials at the same temperature.

Field core. Field core was collected from different wells in the Monument Butte field. The cores were obtained from the State of Utah Department of Natural Resources – Utah Geological Survey. Three sets of core pairs were selected from the plugs for waterflooding studies. One pair (samples 3 and 4) was from well Paiute 34-8, another (samples 7 and 8) was from well Mon Butte 3A-35, and the other pair (samples 15 and 16) was from well Allen 34-5. Porosity and permeability were calculated using the procedure described above for these six core plugs. Core details and analysis results are shown in Table 10.

Because of low permeability and limitations on injection pressure, only two of the field core plugs were found to be suitable for oil recovery tests. Core plugs 15 and 16 from the Allen 34-5 had high enough permeability to be flooded at rates greater than 0.1 ft/day. Due to the epoxy coating that sealed the cores, the maximum allowable injection pressure was 100 psig. The connate water for both core plugs was synthetic Monument Butte reservoir brine (MBRB). The injection brine for Core 15 was MBRB (see Table 5 and Table 6) while the injection brine for Core 16 was the low-salinity field injection water (see Table 7 and Table 8). Both cores were flooded at an injection rate of 0.3 ft/D with a differential pressure of 60 psi across the core. The initial water saturation of Core 15 was 19.0% and the initial water saturation of Core 16 was 22.5%. Results for the two waterfloods (see Figure 7) show a significant increase in recovery from the low-salinity waterflood compared to the full-strength MBRB waterflood. At 10 pore volumes, the formation water flood recovered 37.5% of the OOIP, while the low salinity waterflood recovered 42.1% of the OOIP, which is an increase of 12.4%.

Discussion. This work is a continuation of laboratory work that began using Berea sandstone that had been stored for more than five years at 131°F (55°C). Comparative corefloods using this rock, CS crude oil, and CS reservoir brine showed no differences in oil recovery from full-strength CSRB and diluted CSRB. However, the same tests using a new block of Berea sandstone that had not been stored at that elevated temperature (131°F) showed that injecting low salinity brine significantly increased the oil recovery from laboratory waterfloods. The difference between the two sets of corefloods was the long term storage temperature of the rock. Long term storage of Berea sandstone at 131°F or above may deactivate the clay particles and result in clay that is insensitive to wettability changes caused by low-salinity waterflooding. More work needs to be done, however, to determine the relationships between clay quantity, species, and geometry and the changes in clay/brine/crude oil interactions and wettability and the improved oil recovery that results from dilute brine waterflooding.

Corefloods using Minnelusa reservoir fluids. Temperature differenced played a major role in the tests using the Minnelusa fluids system as well. The first tests using Minnelusa reservoir fluids and Berea sandstone the cores were aged at 131°F, but waterflooded at room temperature and resulted in no increase in oil recovery from injecting low-salinity brine. However, when the aging and flooding temperatures were both increased to the actual reservoir temperature of 167°F (75°C), oil recovery was significantly increased by injecting the low-salinity (diluted) MRB compared to full strength MRB waterfloods (from 49.0% to 55.6% of OOIP). Based on these results, it appears that the many Minnelusa fields in the Powder River Basin may be amenable to low-salinity waterflooding.

Monument Butte field evaluation. The evaluation of the Monument Butte field was fairly straightforward. Some good quality cores were collected from the core library at the Utah Geological Survey. Berea sandstone cores were run before field core in order to get some preliminary indications as to the applicability of low-salinity waterflooding in the field. The Berea sandstone coreflood results indicated that low-salinity flooding showed good potential for increased oil recovery and further tests using field cores were done.

Waterfloods using field cores and reservoir fluids substantiated the preliminary results obtained using Berea sandstone. Oil recovery was increased by 12.4% when fresh water was used as the injection water as opposed to the injection of formation brine. Both pairs of waterfloods (one using Berea sandstone and the other using reservoir core) done with Monument Butte reservoir fluids resulted in higher recovery from the fresh water flood compared to the formation waterflood. This is a significant finding, but should be tempered because this is the result of only four corefloods.

These findings can be useful when planning the expansion of waterfloods in the Monument Butte field. It is suggested that, provided formation damage is not an issue, the operators use fresh water when expanding the waterflood to new areas of the field and re-inject produced water into areas of the field that are already under waterflood.

Conclusions

Rock properties, especially clay, appear to play an important role in improved oil recovery from waterfloods using low-salinity injection water. Long-term storage of dry Berea sandstone, and possibly other rocks of interest, at temperatures above 131°F (55°C), may cause unwanted or unintended changes in the behavior of the clay, especially in regard to wettability alteration.

Aging temperature and flooding temperature both appear to play a major role in altering wettability with a concomitant improvement in oil recovery by injection of low salinity water.

The higher differential pressures routinely seen during low-salinity flooding compared to higher-salinity formation brine flooding did not result in higher oil recoveries.

For the Minnelusa fluids/Berea sandstone ensemble, lower aging and flooding temperatures (131°F [55°C] and 70°F [21°C] respectively) were insufficient to induce the wetting changes necessary for low-salinity flooding to enhance recovery; however, higher aging and flooding temperatures of 167°F (75°C) resulted in a marked increase in recovery from low-salinity floods compared to the higher-salinity floods.

Waterflood tests done in the laboratory using Monument Butte field core, crude oil, and formation water resulted in higher oil recovery from low-salinity flooding than from higher salinity floods. Low salinity injection water should be considered when expanding the waterflood to new areas of the field. Recycled produced water should only be used as a source for injection water in areas of the field where the waterflood has been operating for longer periods.

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Nomenclature

k_g	permeability to gas, md
k_w	permeability to water, md
m_d	mass of dry core, g
m_w	mass of wet core, g
s_o	oil saturation, fraction
s_{or}	residual oil saturation after waterflooding, fraction
s_w	water saturation, fraction
s_{wi}	initial water saturation, fraction
T_{age}	temperature of core during the aging period,
T_{flood}	temperature of the core during the waterflooding period
V_e	dead volume at the ends of the core, mL
V_p	pore volume of the core, mL
V_w	volume of the produced water, mL
ρ_w	density of water inside rock pores, g/mL
ϕ	porosity, fraction

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Tables

Table 1. Properties of Berea sandstone cores used with CS crude oil to explore the effect of changing the salinity of both the connate brine and the injection brine. Length and diameter of all cores were 3.0 in. (7.62 cm) and 1.5 in. (3.81 cm) respectively.

Core	k_g, md	ϕ, %	S_{wi}, %
W22	1188	24.2	22.7
W20	1391	24.4	22.2
W21	1185	24.3	23.6
W23	1068	23.6	26.6

Table 2. Properties of Berea sandstone cores used with Minnelusa crude oil to study the effects of changing the salinity of connate and injection brine at room temperature. Length and diameter of all cores were 3.0 in. (7.62 cm) and 1.5 in. (3.81 cm) respectively.

Core	k_g, md	k_w, md	ϕ, %	S_{wi}, %
INL-11	182	134	19.7	26.9
INL-12	141	105	20.3	24.7
INL-13	233	159	20.5	24.9
INL-14	185	154	20.4	24.4
INL-15	232	164	21.5	24.7
INL-16	239	155	20.4	25.2
INL-17	217	172	20.7	26.4
INL-18	125	90	18.7	25.1

Table 3. Synthetic Minnelusa formation brine composition used in corefloods.

Component	Concentration, g/L
NaCl	29.803
$CaCl_2 * 2H_2O$	2.787
Na_2SO_4	5.903
$MgSO_4 * 7H_2O$	1.723

Table 4. Core properties and flooding data for waterfloods at 167°F (75°C) with Minnelusa crude oil.

Core	ϕ, %	k_g, md	k_w, md	S_{wi}, %	S_{or}, %	Aging time, D	Injection brine
INL-19	20.2	225	130	23.2	25.6	15	0.01 MRB
INL-20	18.5	132	88	26.7	32.2	18	0.01 MRB
INL-21	19.7	181	117	25.2	34.8	16	0.01 MRB
INL-22	18.3	132	92	31.5	32.9	16	0.01 MRB
INL-23	20.3	211	145	27.1	35.7	14	0.01 MRB
INL-24	19.9	218	151	27.5	36.8	15	MRB
INL-25	19.9	180	141	27.4	37.3	14	MRB

Table 5. Dissolved solids analysis for the formation water, Monument Butte field.

Dissolved Solids	Concentration, mg/L
Sodium, Na^-	4425
Potassium, K^-	16
Calcium, Ca^{+2}	19
Magnesium, Mg^{+2}	4
Total cations	4464
Chloride, Cl^-	6282
Bicarbonate, HCO_3^-	1034
Sulfate, SO_4^{-2}	1
Total anions	7316
Total dissolved solids	11780

Table 6. Synthetic formation brine composition for Monument Butte field.

Reservoir brine constituents	Concentration, g/L
NaCl	10.282
$NaHCO_3$	1.389
$KHCO_3$	0.041
$CaCl_2 \bullet 2H_2O$	0.070
$MgCl_2 \bullet 6H_2O$	0.031
$MgSO_4 \bullet 7H_2O$	0.003

Table 7. Average injection water analysis for the Monument Butte field.

Dissolved Solids	Concentration, mg/L
Sodium, Na^-	95
Calcium, Ca^{+2}	49
Magnesium, Mg^{+2}	26
Total cations	170
Chloride, Cl^-	154
Bicarbonate, HCO_3^-	224
Sulfate, SO_4^{-2}	35
Total anions	413
Total dissolved solids	583

Table 8. Synthetic injection water composition for Monument Butte field, Uinta Basin, Utah.

Injection water components	g/L
NaCl	0.029
$NaHCO_3$	0.308
$CaCl_2 * 2H_2O$	0.180
$MgCl_2 * 6H_2O$	0.143
$MgSO_4 * 7H_2O$	0.090

Table 9. Properties and dimensions of the two Berea sandstone cores used in waterfloods with Monument Butte field fluids.

	A28	A29
Length, in	3.01	2.98
Diameter, in	1.46	1.47
Porosity, %	19.9	19.3
Gas permeability, md	207	147
Brine permeability, md	127.2	67.4
Initial water saturation, %	22.1	17.5

Table 10. Routine core analysis test results for core plugs collected from the Monument Butte field.

Well name	Paiute 34-8		Mon Butte 3A-35		Allen 34-5	
Plug number	3	4	7	8	15	16
Approximate depth, ft	4058.90	4059.20	4998.55	4998.70	5024.85	5025.00
Length, in.	2.126	2.213	2.694	2.458	3.023	3.023
Diameter, in.	1.484	1.485	1.482	1.482	1.484	1.482
Porosity, %	15.5	14.2	13.9	13.8	16.0	16.0
Gas permeability, md	4.3	3.6	2.4	2.2	32.2	38.9
Initial water saturation, %	—	—	—	—	19.0	22.5

Figures

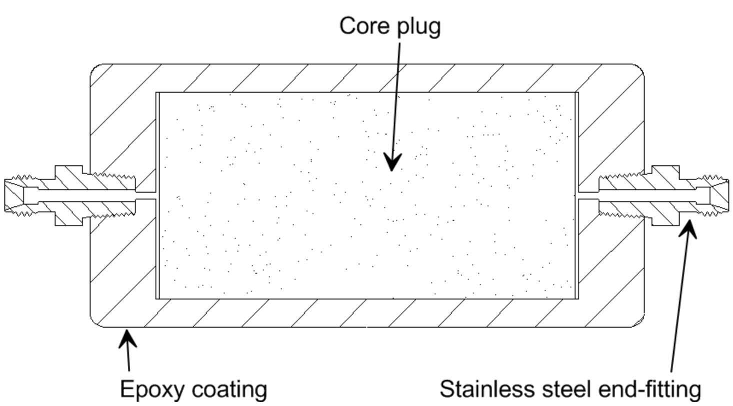

Figure 1. Schematic of epoxy-coated core used in experimentation.

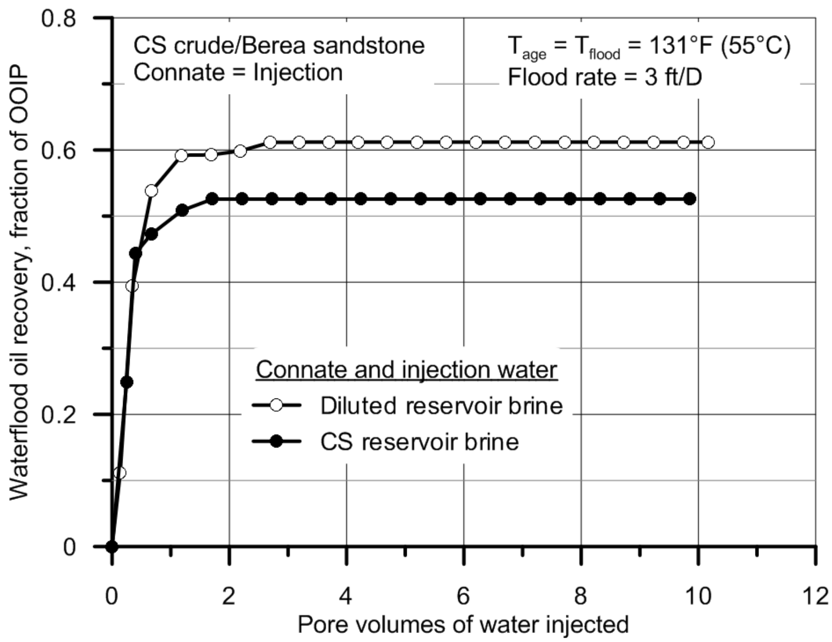

Figure 2. Corefloods with Berea sandstone and CS crude oil showing effect of brine dilution on waterflood oil recovery. Each curve represents the average of two separate corefloods.

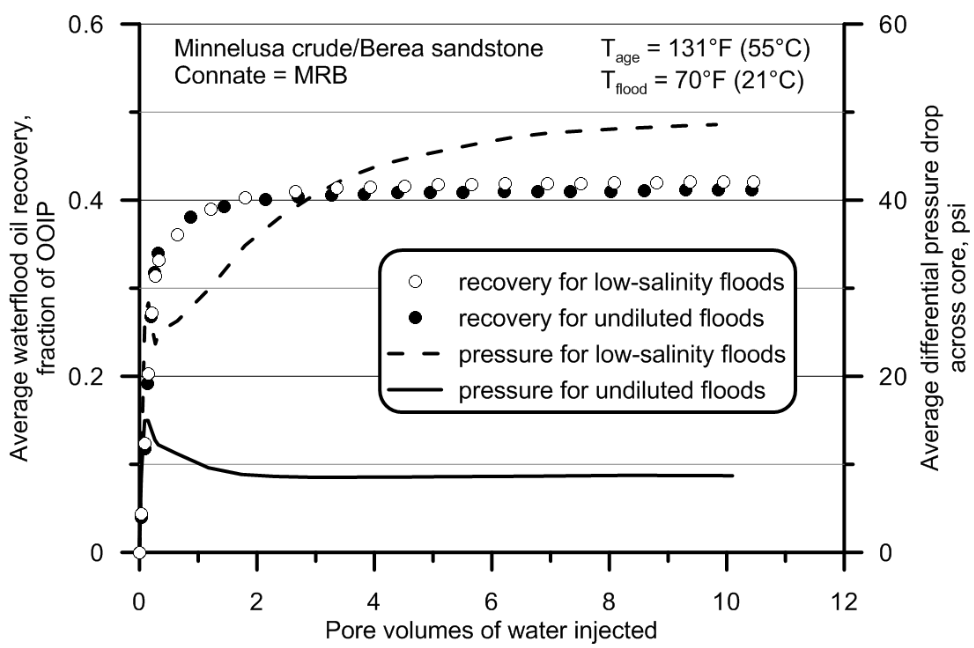

Figure 3. Average oil recovery curves for four waterfloods using full strength reservoir brine as the injection water and four waterfloods using a 100-fold dilution as the injection water. Each curve or data series represents the average of four corefloods.

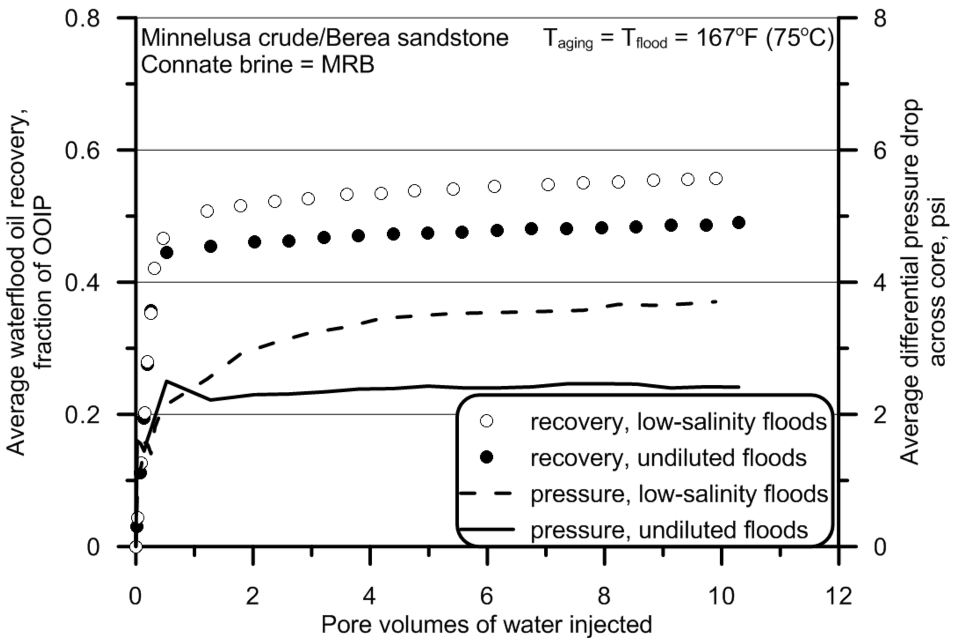

Figure 4. Average of oil recovery curves for waterfloods of Berea sandstone cores using Minnelusa crude oil and with Minnelusa formation brine as the connate water using an aging and flooding temperature of 167°F (75°C). Flood rate = 3 ft/day.

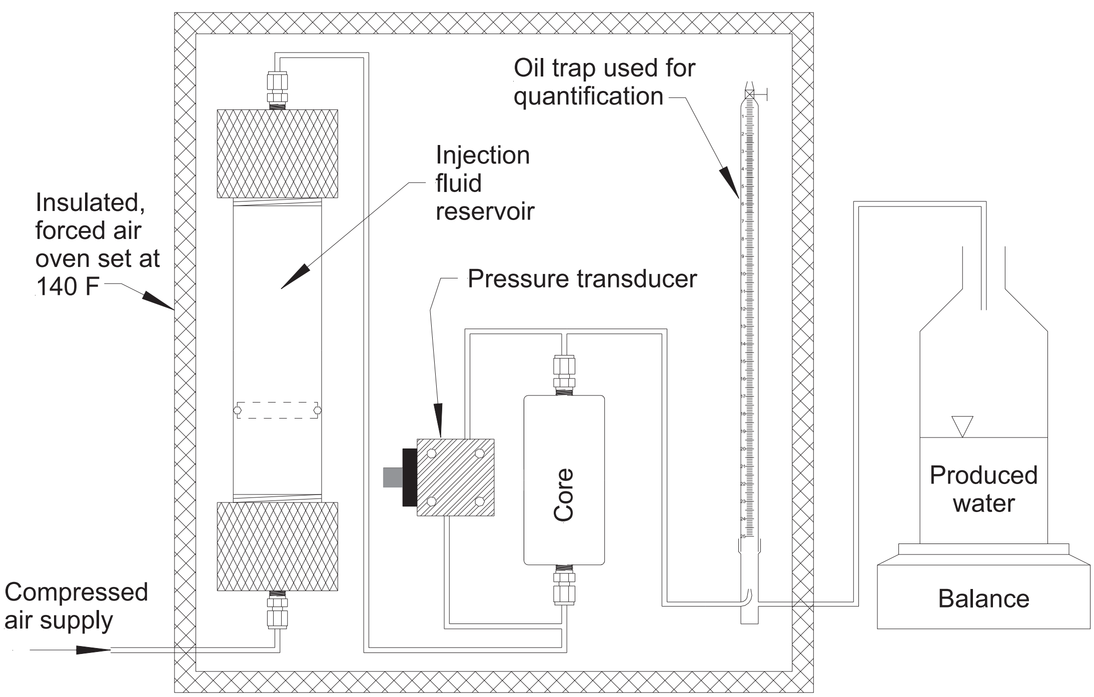

Figure 5. Laboratory setup used for waterflooding with Monument Butte formation fluids.

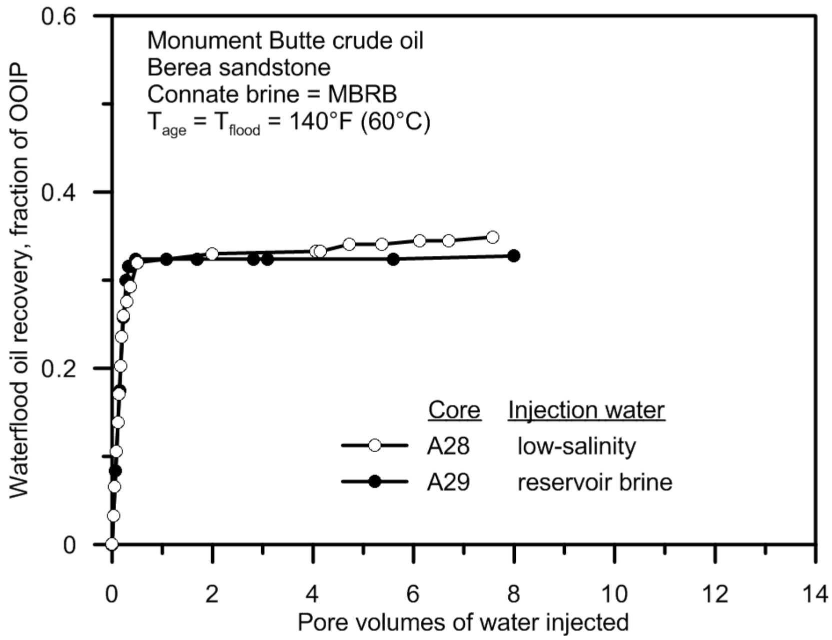

Figure 6. Recovery from Berea sandstone using field crude oil and field waters. Flood front velocity was 3.0 ft/day.

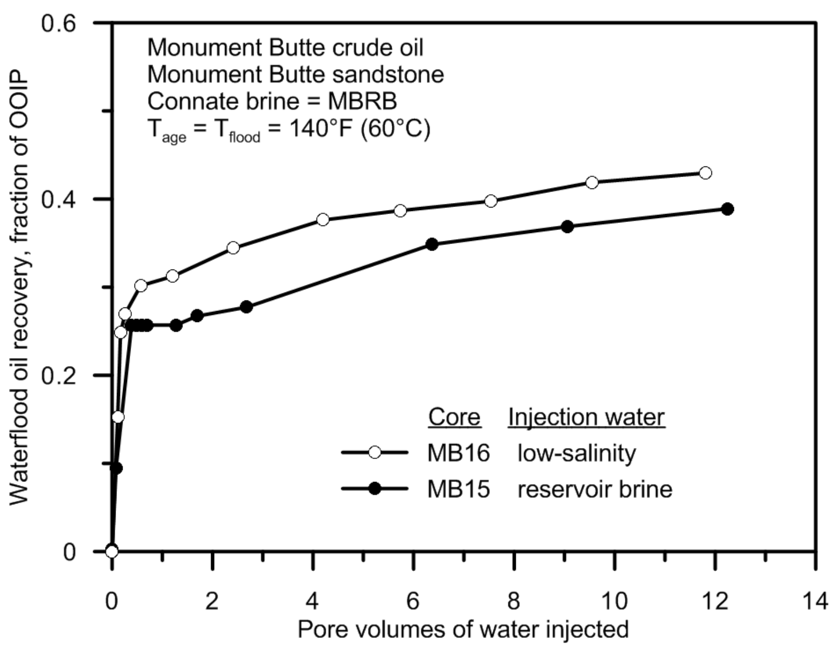

Figure 7. Oil recovery from two Monument Butte field cores showing increase in recovery when low-salinity injection water is used. Flood front velocity was 0.3 ft/day